Filing Receipt

Received - 2022-10-27 02:27:59 PM
Control Number - 53719
ItemNumber - 255

SOAH DOCKET NO. 473-22-04394
PUC DOCKET NO. 53719

APPLICATION OF ENTERGY	**§**	**BEFORE THE STATE OFFICE**
TEXAS, INC. FOR AUTHORITY	**§**	**OF**
TO CHANGE RATES	**§**	**ADMINISTRATIVE HEARINGS**

WORKPAPERS TO THE DIRECT TESTIMONY

OF

JEFFRY POLLOCK

ON BEHALF OF TEXAS INDUSTRIAL ENERGY CONSUMERS

October 27, 2022

RECEIVED

2020 DEC 16 PM 12: 25

PUBLIC UTILITY COMMISSION

DOCKET NO. 51381

APPLICATION OF ENTERGY TEXAS, INC. TO ESTABLISH A GENERATION COST RECOVERY RIDER RELATED TO THE MONTGOMERY COUNTY POWER STATION	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

UNOPPOSED STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Stipulation") is entered into between and among Entergy Texas, Inc. ("ETI"), the Staff of the Public Utility Commission of Texas, the Office of Public Utility Counsel, and Texas Industrial Energy Consumers. The Cities of Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange ("Cities") are not signatories to the Stipulation but do not oppose its terms.

The parties joining this Stipulation shall be referred to individually as a Signatory and collectively as the Signatories. The Signatories submit this Stipulation to the Commission as representing a just and reasonable disposition of the issues related to this docket consistent with the public interest. The Signatories request approval of this Stipulation and entry of findings of fact and conclusions of law consistent with that approval.

I. BACKGROUND

On October 5, 2020, ETI filed its Application seeking Public Utility Commission of Texas ("Commission") approval to establish a Generation Cost Recovery Rider ("GCRR") to begin recovering its investment in the Montgomery County Power Station ("MCPS"). ETI's Application includes the Company's MCPS-related capital investment through August 31, 2020. ETI currently anticipates that MCPS will be placed in service to ETI customers on or around January 1, 2021. Within 60 days of MCPS being placed in service, ETI will file an update to its Application to include in its GCRR its MCPS-related capital investment incurred after August 31, 2020.

The Signatories believe that a resolution of this docket pursuant to the terms stated herein is in the public interest and that the result is reasonable under the circumstances. Settlement of this matter will also conserve the resources of the public and the Signatories and will eliminate

48

controversy. The Signatories jointly request approval of this Stipulation and entry of a Commission order, including findings of fact and conclusions of law, consistent with that approval.

II. STIPULATION

By this Stipulation, the Signatories agree to the following terms in settlement of the issues subject to determination in Docket No. 51381, and agree as follows:

A. Regulatory Approval

In a manner consistent with the terms of this Stipulation, the Commission should issue an Order approving ETI's application to establish a GCRR to begin recovering the Company's investment in MCPS on the day MCPS is placed in service to ETI customers.

B. Agreed Terms and Conditions

The Signatories agree:

1) ETI will propose to update the MCPS-related invested capital included in its GCRR to reflect the 7.55% partial sale of MCPS to East Texas Electric Cooperative, Inc. ("ETEC"), assuming that sale is consummated. ETI will propose this update in a GCRR proceeding related to the Hardin County Peaking Facility or, if such a proceeding is not filed, in a compliance filing as soon as reasonably possible following the 7.55% partial sale of MCPS to ETEC. The reduction in MCPS-related invested capital shall include the full sale price received for the 7.55% of MCPS, including any amounts associated with depreciation or other costs already recovered through the GCRR, such that there is no over-recovery of costs. ETI will propose that the updated GCRR rate (reflecting the MCPS-related reduction) relate back to the day the sale closes with carrying costs at ETI's weighted average cost of capital.

2) In this docket and in any GCRR proceeding prior to ETI's next base rate case, ETI will propose and the signatories will support a depreciation rate intended to fully depreciate MCPS over 38 years from the day it is placed in service.

3) ETI will remove a total of $4,849,688 from its requested GCRR revenue requirement. The reduction includes: (1) a reduction to power generation facility net invested capital for items including but not limited to advertising, alcohol purchased with business meals, education expenses, groundbreaking ceremony expenses, and incentive compensation awarded based on operational measures but funded based on a financial trigger; (2) a reduction to depreciation expense to reflect the agreement in provision 2) above; and (3) the flow through effects of the combined reductions.

4) ETI retains its right to seek inclusion of the amount removed for incentive compensation in rate base in its next base rate case, and all parties reserve the right to

challenge in ETI's next base rate case the prudence and reasonableness of costs included in ETI's GCRR.

5) Settlement Schedules filed with the Testimony of Allison P. Lofton in Support of the Stipulation include the starting amounts for the next update to ETI's GCRR for actual capital investment in MCPS on and after September 1, 2020 under 16 TAC § 24.248(h).

C. Obligation to Support the Stipulation

The Signatories support this Stipulation and request entry of the findings of fact, conclusions of law, and ordering paragraphs as reflected in Exhibit A to this Stipulation.

D. Agreed Evidence

The Signatories agree to the admission into evidence of the documents listed in Attachment A to the Unopposed Joint Motion to Admit Evidence.

E. Effect of the Stipulation

1. The Signatories arrived at this Stipulation through extensive negotiation and compromise. This Stipulation reflects a compromise, settlement, and accommodation among the Signatories, and the Signatories agree that the terms and conditions herein are interdependent. The Signatories agree that this Stipulation is in the public interest. All actions by the Signatories contemplated or required by this Stipulation are conditioned upon entry by the Commission of a final order fully consistent with this Stipulation. If the Commission does not accept this Stipulation as presented or enters an order inconsistent with any material term of this Stipulation, any Signatory shall be released from all commitments and obligations, and shall have the right to seek hearing on all issues, present evidence, and advance any positions it desires, as if it had not been a Signatory.

2. This Stipulation is binding on each Signatory only for the purpose of settling the issues as set out herein and for no other purpose. Except to the extent that this Stipulation expressly governs a Signatory's rights and obligations for future periods, this Stipulation, including all terms provided herein, shall not be binding or precedential on a Signatory outside of this case except for a proceeding to enforce the terms of this Stipulation. The Signatories acknowledge and agree that a Signatory's support of the matters contained in this Stipulation may differ from its position or testimony in other proceedings not referenced in this Stipulation. To the extent there is a difference, a Signatory does not waive its position in such other

proceedings. Because this is a settlement agreement, a Signatory is under no obligation to take the same position as set out in this Stipulation in other proceedings not referenced in this Stipulation, whether those proceedings present the same or a different set of circumstances. A Signatory's agreement to entry of a final order of the Commission consistent with this Stipulation should not be regarded as an agreement to the appropriateness or correctness of any assumptions, methodology, or legal or regulatory principle that may have been employed in reaching this Stipulation.

3. The failure to litigate any specific issue in this docket does not waive any Signatory's rights to contest that issue in any other proceeding, and the failure to litigate an issue cannot be asserted as a defense or estoppel, or any similar argument, by or against any Signatory in any other proceeding. The terms of this Stipulation may not be used either as an admission or concession of any sort or as evidence in any proceeding except to enforce the terms of this Stipulation. Oral or written statements made during the course of the settlement negotiations may not be used for any purposes other than as necessary to support the entry by the Commission of an order implementing this Stipulation. All oral or written statements made during the course of the settlement negotiations are governed by Texas Rule of Evidence 408.

4. There are no third party beneficiaries of this Stipulation. This Stipulation contains the entire understanding and agreement of the Signatories, supersedes all other written and oral exchanges or negotiations among them or their representatives with respect to the subjects contained herein. Neither this Stipulation nor any of the terms of this Stipulation may be altered, amended, waived, terminated, or modified, except by a writing properly executed by the Signatories.

F. Execution

The Signatories agree that this Stipulation may be executed in multiple counterparts and filed with facsimile or computer image signatures. Each person executing this Stipulation represents that he or she is authorized to sign on behalf of the party represented.

Executed this 16 day of December 2020:

SIGNATORIES:

ENTERGY TEXAS, INC.

By: ______________________
George G. Hoyt
Attorney of Record

PUBLIC UTILITY COMMISSION OF TEXAS STAFF

By: */s/ Eleanor D'Ambrosio w/ permission*
Eleanor D'Ambrosio
Attorney of Record

OFFICE OF PUBLIC UTILITY COUNSEL

By: */s/ Zachary Stephenson w/ permission*
Chris Ekoh
Zachary Stephenson
Attorneys of Record

TEXAS INDUSTRIAL ENERGY CONSUMERS

By: */s/ Rex VanMiddlesworth w/ permission*

Rex Van Middlesworth
Attorney of Record

UNOPPOSED:

CITIES

By: */s/ Daniel Lawton w/ permission*

Daniel Lawton
Molly Mayhall-Vandervoort
Attorneys of Record

DOCKET NO. 51381

APPLICATION OF ENTERGY TEXAS, INC. TO ESTABLISH A GENERATION COST RECOVERY RIDER RELATED TO THE MONTGOMERY COUNTY POWER STATION	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

PROPOSED ORDER

This Order addresses the application of Entergy Texas, Inc. (ETI) to establish a Generation Cost Recovery Rider (GCRR) to begin recovering a return of and on its investment in the Montgomery County Power Station (MCPS). ETI filed an unopposed agreement that each of the parties either supported or did not oppose. After considering the factors set forth in PURA[1] § 36.213 and 16 Tex. Admin. Code § 25.248 (TAC), the application is approved in accordance with the parties' agreement to the extent provided in this Order.

I. Findings of Fact

The Commission makes the following findings of fact.

Applicant

1. ETI is a subsidiary of Entergy Corporation and a fully integrated utility that owns equipment and facilities to generate, transmit, distribute, and sell electricity in Texas.

2. ETI is authorized under certificate of convenience and necessity (CCN) number 30076 to provide service to the public and to provide retail electric utility service within its certificated service area.

3. The Commission regulates ETI's retail operations.

4. The Federal Energy Regulatory Commission regulates ETI's wholesale electric operations.

Application

5. On October 5, 2020, ETI filed an application requesting Commission approval to establish a GCRR pursuant to PURA § 36.213 and 16 TAC § 25.248 in order to begin recovering a return of and on its capital investment in MCPS.

---

[1] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001 – 66.016.

6. The proposed GCRR, which included ETI's MCPS-related generation invested capital of $685,894,634 incurred through August 31, 2020 and amounts associated with ETI's return on net generation facility invested capital, depreciation, federal income taxes, and other taxes, was designed to collect approximately $91 million on an annual basis from ETI customers.

7. In support of its application, ETI included the direct testimony of five witnesses.

8. In Order No. 2 filed on October 16, 2020, the Commission administrative law judge (ALJ) found the application sufficient.

Notice of the Application and Interventions

9. In accordance with 16 TAC § 25.248(g)(2), ETI notified all parties to its last base rate proceeding that the application was filed. The notice was provided by first-class mail, was mailed the same day the application was filed, specified the docket number assigned to the application, and included a copy of the application.

10. On October 6, 2020, ETI filed proof of notice.

11. In Order No. 2, filed on October 16, 2020, the Commission ALJ found ETI's notice sufficient.

12. Motions to intervene were submitted by the Office of Public Utility Counsel (OPUC), Texas Industrial Energy Consumers (TIEC), and the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange (collectively, Cities).

13. In Order No. 2, filed on October 16, 2020, the Commission ALJ granted the motions to intervene submitted by OPUC, TIEC, and Cities.

Testimony and Statements of Position

14. The application filed on October 5, 2020 included the direct testimonies of Abigail Weaver, Anastasia Meyer, Richard Lain, Allison P. Lofton, Gary Dickens, and Kristin Sasser.

15. On December 7, 2020, TIEC filed the direct testimony of Jeffry C. Pollock.

16. On December 7, 2020, OPUC filed the direct testimony of Constance T. Cannady.

17. On December 7, 2020, Cities filed the direct testimony of Karl J. Nalepa.

18. On December 16, 2020, ETI filed the testimony of Allison P. Lofton in support of the agreement.

19. On December 16, 2020, Commission Staff filed the testimony of Reginald Tuvilla in support of the agreement.

Procedural Matters

20. In Order No. 1 filed on October 8, 2020, the Commission ALJ entered a protective order, established filing procedures, established an intervention deadline, and required Commission Staff to file comments and recommendations regarding ETI's application and notice and to propose a procedural schedule.

21. In Order No. 2 filed on October 16, 2020, the Commission ALJ granted the interventions of TIEC, Cities, and OPUC, found ETI's application and notice sufficient, and established an initial procedural schedule.

22. On November 9, 2020, TIEC, Cities, and OPUC each filed a request for hearing.

23. In Order No. 3 filed on November 20, 2020, the Commission ALJ addressed potential hearing dates, encouraged the parties to develop procedural schedules, and found that the requirements for informal disposition under 16 TAC § 22.35 were not met at that time.

24. In Order No. 4 filed on December 1, 2020, the Commission ALJ established a procedural schedule that included procedures and deadlines for intervenor and Commission Staff direct testimony, ETI rebuttal testimony, a prehearing conference, and a hearing on the merits to be presided over by the Commission on December 17 and 18, 2020.

25. On December 16, 2020, ETI filed the agreement, proposed order, agreed motion to admit evidence, and the testimony, exhibits, and schedules of Allison P. Lofton in support of the agreement.

26. In Order No. 5 filed on December 9, 2020, the Commission ALJ granted the agreed motion to abate the procedural schedule.

Evidentiary Record

27. In Order No. 6 filed on ______, the Commission ALJ admitted the following evidence:
    - ETI's application, including all attachments, filed on October 5, 2020
    - Direct testimony of ETI witness Abigail Weaver, filed on October 5, 2020
    - Direct testimony and exhibits of ETI witness Richard Lain, filed on October 5, 2020
    - Direct testimony and exhibit of ETI witness Allison P. Lofton, filed on October 5, 2020
    - Direct testimony and exhibits of ETI witness Gary Dickens, filed on October 5, 2020
    - Direct testimony and exhibit of ETI witness Kristin Sasser, filed on October 5, 2020
    - ETI's Proof of Notice, filed on October 6, 2020
    - Direct testimony and exhibits of TIEC witness Jeffry Pollock, filed on December 7, 2020
    - Direct testimony and exhibits of OPUC witness Constance T. Cannady, filed on December 7, 2020
    - Direct testimony and exhibits of Cities witness Karl J. Nalepa, filed on December 7, 2020
    - The testimony, exhibits, and schedules of ETI witness Allison P. Lofton, filed in support of the agreement on December 16, 2020
    - The testimony of Commission Staff witness Reginald Tuvilla filed in support of the agreement on December 16, 2020
    - The agreement and its attachments

Description of the Power Generation Facility

28. On July 28, 2017, in Docket No. 46416, *Application of Entergy Texas, Inc. to Amend Its Certificate of Convenience and Necessity to Construct Montgomery County Power Station in Montgomery County*, the Commission issued an order amending ETI's CCN No. 30076 to include the construction, ownership, and operation of MCPS.

29. MCPS consists of two Mitsubishi Hitachi Power Systems 501 GAC combustion turbines, two Nooter Eriksen heat recovery steam generators with duct firing, and one Toshiba steam turbine generator in a 2x1 combined cycle configuration, as well as other balance of plant equipment, including the use of a cooling tower for closed-cycle cooling operations.

30. MCPS is located near Willis, Texas, adjacent to the existing Lewis Creek facility.

31. ETI requests that its proposed GCRR be made effective as of the date MCPS begins providing service to ETI's customers, which ETI expects to be January 1, 2021.

<u>The Agreement</u>

32. The agreement was executed by ETI, Commission Staff, OPUC, and TIEC. Cities are not signatories to the agreement but do not oppose its terms.

33. The signatories agreed that the agreement resolves all issues between them related to this proceeding and that the agreement is binding on each of the signatories for the purpose of resolving the issues set forth in the agreement.

34. The signatories agreed that, subject to the terms of the agreement, ETI's application should be approved.

35. The signatories agreed that ETI will propose to update the MCPS-related invested capital included in its GCRR to reflect the planned 7.55% partial sale of MCPS to East Texas Electric Cooperative, Inc. (ETEC), assuming that sale is consummated. ETI will propose this update in a GCRR proceeding related to the Hardin County Peaking Facility or, if such a proceeding is not filed, in a compliance filing as soon as reasonably possible following the 7.55% partial sale of MCPS to ETEC. The reduction in MCPS-related invested capital shall include the full sale price received for the 7.55% of MCPS, including any amounts associated with depreciation or other costs already recovered through the GCRR, such that there is no over-recovery of costs. ETI will propose that the updated GCRR rate (reflecting the MCPS-related reduction) relate back to the day the sale closes with carrying costs at ETI's weighted average cost of capital.

36. The signatories agreed that in this docket and in any GCRR proceeding prior to ETI's next base rate case, ETI will propose and the signatories will support a depreciation rate intended to fully depreciate MCPS over 38 years from the day it is placed in service.

37. The signatories agreed ETI will remove a total of $4,849,688 from its requested GCRR revenue requirement. The reduction includes: (1) a reduction to power generation facility net invested capital for items including but not limited to advertising, alcohol purchased with business meals, education expenses, groundbreaking ceremony expenses, and

incentive compensation awarded based on operational measures but funded based on a financial trigger; (2) a reduction to depreciation expense to reflect the parties' agreement regarding the depreciation rate to be applied to MCPS until ETI's next base rate proceeding; and (3) the flow through effects of the combined reductions.

38. The signatories agreed that ETI retains its right to seek inclusion of the amount removed for incentive compensation in rate base in its next base rate case, and all parties reserve the right to challenge in ETI's next base rate case the prudence and reasonableness of costs included in ETI's GCRR.

39. The signatories agree that the Settlement Schedules filed with the Testimony of Allison P. Lofton in Support of the Stipulation include the starting amounts for the next update to ETI's GCRR for actual capital investment in MCPS on and after September 1, 2020 under 16 TAC § 24.248(h).

40. Exhibit APL-S-1 to the settlement testimony of Allison P. Lofton contains a revised GCRR revenue requirement that reflects the terms of the agreement.

41. Exhibit APL-S-2 to the settlement testimony of Allison P. Lofton contains a revised GCRR tariff and rates that reflect the revised GCRR revenue requirement in accordance with the terms of the agreement.

42. The agreement, taken as a whole, is a just and reasonable resolution of the issues, is in the public interest, and should be approved.

Informal Disposition

43. More than 15 days have passed since the completion of notice provided in this docket.

44. No hearing is necessary.

45. All parties in this proceeding are either signatories to the agreement or did not oppose the agreement.

46. The decision is not adverse to any party.

II. Conclusions of Law

The Commission makes the following conclusions of law.

1. ETI is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

2. The Commission has jurisdiction and authority over this proceeding under PURA §§ 14.001 and 36.213.

3. This docket was processed in accordance with the requirements of PURA, the Administrative Procedure Act,[2] and Commission rules.

4. ETI provided notice of the application in accordance with 16 TAC § 22.248(g)(2).

5. The agreement, as construed by this Order, is a just and reasonable resolution of all issues it addresses, is supported by a preponderance of the credible evidence in the record, and is consistent with the relevant provisions of PURA and Commission rules.

6. The application, as modified by the agreement and this Order, meets the applicable requirements of PURA § 36.213.

7. The application may be approved without a hearing under the Administrative Procedure Act and Commission rules.

8. The requirements for informal disposition in 16 TAC § 22.35 have been met in this proceeding.

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The application, as modified by the agreement and this Order, is approved.

2. The Commission approves the GCRR tariff included as Exhibit APL-S-2 to the Settlement Testimony of Allison P. Lofton, effective with usage on and after the date MCPS begins providing service to ETI's customers.

3. ETI shall propose to update the MCPS-related invested capital included in its GCRR to reflect the planned 7.55% partial sale of MCPS to ETEC, assuming that sale is consummated. ETI shall propose this update in a GCRR proceeding related to the Hardin

---

[2] Administrative Procedure Act, Tex. Gov't Code §§ 2001.001-.902.

County Peaking Facility or, if such a proceeding is not filed, in a compliance filing as soon as reasonably possible following the 7.55% partial sale of MCPS to ETEC. The reduction in MCPS-related invested capital shall include the full sale price received for the 7.55% of MCPS, including any amounts associated with depreciation or other costs already recovered through the GCRR, such that there is no over-recovery of costs. ETI shall propose that the updated GCRR rate (reflecting the MCPS-related reduction) relate back to the day the sale closes with carrying costs at ETI's weighted average cost of capital.

4. The rates approved by this Order are based on a depreciation rate intended to fully depreciate MCPS over 38 years from the day it is placed in service. In any GCRR proceeding prior to ETI's next base rate case, ETI shall propose and the signatories shall not oppose a depreciation rate intended to fully depreciate MCPS over 38 years from the day it is placed in service.

5. Entry of this Order does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the agreement and shall not be regarded as binding holding or precedent as to the appropriateness of any principle or methodology that may underlie the agreement.

6. All other motions and any other requests for general or specific relief, if not expressly granted, are denied.

Signed at Austin, Texas the ______ day of __________ 2020.

PUBLIC UTILITY COMMISSION OF TEXAS

____
DEANN T. WALKER, CHAIRMAN

____
ARTHUR C. D'ANDREA, COMMISSIONER

____
SHELLY BOTKIN, COMMISSIONER

PUC DOCKET NO. 51381
SOAH DOCKET NO. 473-21-2605

2022 JAN 14 PM 1:16

APPLICATION OF ENTERGY TEXAS, INC. TO ESTABLISH A GENERATION COST RECOVERY RIDER RELATED TO THE MONTGOMERY COUNTY POWER STATION	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

This Order addresses the application of Entergy Texas, Inc. to update its generation cost recovery rider (GCRR) to recover a return of and on its investment in the Montgomery County power station. On October 13, 2021, Entergy Texas filed an unopposed agreement between the parties. The Commission approves Entergy Texas's proposed GCRR, as modified by the October 13, 2021 agreement, to the extent provided in this Order.

I. Findings of Fact

The Commission makes the following findings of fact.

Applicant

1. Entergy Texas is a Texas corporation registered with the Texas secretary of state under filing number 800911623.

2. Entergy Texas owns and operates for compensation equipment and facilities to generate, transmit, distribute, and sell electricity in Texas.

3. Entergy Texas is required under certificate of convenience and necessity (CCN) number 30076 to provide service to the public and to provide retail electric utility service within its certificated service area.

4. Entergy Texas is an electric utility that operates solely outside of the Electric Reliability Council of Texas (ERCOT) region.

118

Description of the Power Generation Facility

5. On July 28, 2017, in Docket No. 46416,[1] the Commission issued an order amending Entergy Texas's CCN number 30076 to include the construction, ownership, and operation of the Montgomery County power station.

6. The Montgomery County power station consists of two Mitsubishi Hitachi Power Systems 501 GAC combustion turbines, two Nooter Eriksen heat recovery steam generators with duct firing, and one Toshiba steam turbine generator in a 2x1 combined cycle configuration, as well as other balance of plant equipment, including the use of a cooling tower for closed-cycle cooling operations.

7. The Montgomery County power station is located near Willis, Texas, adjacent to Entergy Texas's existing Lewis Creek generation facility.

8. On January 6, 2021, Entergy Texas filed the affidavit of Gary Dickens, vice president, project and construction management for Entergy Services, LLC, testifying that the Montgomery County power station began providing service to Entergy Texas's customers on January 1, 2021.

9. On April 28, 2020, Entergy Texas and East Texas Electric Cooperative, Inc. (ETEC) filed a joint report and application in Docket No. 50790[2] seeking Commission approval for Entergy Texas to transfer to ETEC a minority interest in the Montgomery County power station and for Entergy Texas to acquire from ETEC the Hardin County peaking facility.

10. On April 7, 2021, the Commission approved the joint report and application filed in Docket No. 50790 as modified by an unopposed agreement between the parties to that proceeding.

11. On June 4, 2021, Entergy Texas transferred a 7.56% interest in the Montgomery County power station to ETEC and acquired the Hardin County peaking facility from ETEC. Entergy Texas retained a 92.44% interest in the Montgomery County power station and the

---

[1] *Application of Entergy Texas, Inc. to Amend Its Certificate of Convenience and Necessity to Construct Montgomery County Power Station in Montgomery County*, Docket No. 46416, Order (Jul. 28, 2017).

[2] *Joint Report and Application of Entergy Texas, Inc. and East Texas Electric Cooperative, Inc. for Regulatory Approvals Related to Transfers of the Hardin County Peaking Facility and a Partial Interest in Montgomery County Power Station*, Docket No. 50790, Order (Apr. 7, 2021).

exclusive right to manage, administer, and control the operation and management of that facility.

12. On June 18, 2021, Entergy Texas filed the affidavit of David Wilcox, senior commercial originator at Energy Services, LLC, testifying that both Entergy Texas's sale of the partial interest in the Montgomery County power station to ETEC and Entergy Texas's acquisition of the Hardin County peaking facility from ETEC closed on June 4, 2021.

Initial Application

13. On October 5, 2020, Entergy Texas filed its initial application requesting Commission approval to establish a GCRR under PURA[3] § 36.214[4] and 16 Texas Administrative Code (TAC) § 25.248 to begin recovering a return of and on its capital investment in the Montgomery County power station.

14. In the October 5, 2020 application, the proposed GCRR was designed to recover Entergy Texas's Montgomery County power station-related net generation invested capital of $685,894,634 incurred through August 31, 2020, and amounts associated with Entergy Texas's return on net generation invested capital, depreciation, federal income taxes, and other taxes. This initial application requested an annual GCRR revenue requirement of $90,971,142.

15. On December 1, 2020, Entergy Texas filed an application to amend its GCRR to reflect its acquisition of the Hardin County peaking facility from ETEC in Docket No. 51557.[5]

16. Entergy Texas stated in its application in Docket No. 51557 that the application was intended to result in no change to the GCRR rates established in this proceeding. Entergy Texas further stated that it intended to file in Docket No. 51557, within 60 days after the Hardin County peaking facility began providing service to customers, an application to update the GCRR to reflect Entergy Texas's actual capital investment in the Hardin County

[3] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001–66.016 (PURA).

[4] Formerly, PURA § 36.213 at the time the application was filed but redesignated as PURA § 36.214 by Acts 2021, 87th Leg., R.S., Ch. 915 (H.B. 3607), Sec. 21.001(111), eff. Sept. 1, 2021.

[5] *Application of Entergy Texas, Inc. to Amend Its Generation Cost Recovery Rider to Reflect the Acquisition of the Hardin County Peaking Facility*, Docket No. 51557, Order (Jul. 30, 2021).

peaking facility through the date that it was placed into service, with a reduction to reflect Entergy Texas's sale of a 7.55% non-controlling interest in Entergy Texas's Montgomery County power station to ETEC.

17. On December 16, 2020, Entergy Texas filed on behalf of itself, Commission Staff, the Office of Public Utility Counsel, and Texas Industrial Energy Consumers (collectively, the signatories) an unopposed agreement between the parties that resolves all issues between them related to the October 5, 2020 application.

18. The signatories agreed in the December 16, 2020 agreement that Entergy Texas would propose to update the Montgomery County power station-related invested capital included in its GCRR to reflect the planned 7.55% partial sale of the Montgomery County power station to ETEC, assuming that sale was consummated. The signatories further agreed that such reduction in the Montgomery County power station-related invested capital must include the full sale price received for the 7.55% of the Montgomery County power station, including any amounts associated with depreciation or other costs already recovered through the GCRR, such that there is no over-recovery of costs. The signatories agreed that Entergy Texas would propose that the updated GCRR rate (reflecting the Montgomery County power station-related reduction) relate back to the day the sale closed with carrying costs at Entergy Texas's weighted-average cost of capital.

19. The signatories agreed in the December 16, 2020 agreement that in this docket and in any GCRR proceeding before Entergy Texas's next base-rate case, Entergy Texas would propose and the signatories would support a depreciation rate intended to fully depreciate the Montgomery County power station over 38 years from the day it is placed in service.

20. The signatories agreed in the December 16, 2020 agreement that Entergy Texas would remove a total of $4,849,688 from the GCRR revenue requirement requested in the October 5, 2020 application. The reduction included the following: (a) a reduction to power generation facility net invested capital for items including but not limited to advertising, alcohol, education expenses, groundbreaking ceremony expenses, and incentive compensation; (b) a reduction to depreciation expense to reflect the parties' agreement regarding the depreciation rate to be applied to the Montgomery County power

station until Entergy Texas's next base-rate proceeding; and (c) the flow-through effects of the combined reductions.

21. The signatories agreed in the December 16, 2020 agreement that Entergy Texas retained its right to seek inclusion of the amount removed for incentive compensation in rate base in its next base-rate case, and all parties reserved the right to challenge in Entergy Texas's next base-rate proceeding the prudence and reasonableness of costs included in Entergy Texas's GCRR.

22. The signatories agreed in the December 16, 2020 agreement that the schedules filed with the testimony of Allison P. Lofton in support of that agreement included the starting amounts for the next update to Entergy Texas's GCRR for actual capital investment in the Montgomery County power station on and after September 1, 2020, under 16 TAC § 25.248(h).

23. Exhibit APL-S-1 to Ms. Lofton's testimony in support of the December 16, 2020 agreement contained a revised annual GCRR revenue requirement of $86,121,453 that reflected the terms of that agreement.

24. Exhibit APL-S-2 to Ms. Lofton's testimony in support of the December 16, 2020 agreement contained a revised GCRR tariff and rates that reflected the revised annual GCRR revenue requirement in accordance with the terms of that agreement.

25. In an interim order filed on January 20, 2021, the Commission held that the Commission's GCRR rule, 16 TAC § 25.248, requires that a GCRR application may include only one discrete power generation facility. Accordingly, the Commission held that Entergy Texas could not, in Docket No. 51557, account for the sale of a partial interest in the Montgomery County power station.

26. In the interim order filed on January 20, 2021, the Commission found that if the proposed partial sale of the Montgomery County power station to ETEC closed, Entergy Texas's GCRR should be updated to reflect the sale.

27. In the interim order filed on January 20, 2021, the Commission approved the GCRR rates agreed on in the December 16, 2020 agreement on an interim basis and abated this

proceeding until Entergy Texas notified the Commission that the partial sale to ETEC either closed or would not close or until the Commission ordered otherwise. The Commission also directed Entergy Texas, should it elect to update its GCRR under 16 TAC § 25.248(h) within 60 days after the Montgomery County power station began providing service, to file its GCRR update application in this docket.

28. On January 21, 2021, Entergy Texas filed a clean copy of its GCRR tariff schedule in compliance with the interim order. The schedule has an effective date of January 1, 2021, the date identified by Entergy Texas as the date the Montgomery County power station began providing service to Entergy Texas's customers.

Update Application

29. On March 2, 2021, Entergy Texas filed a second application in this proceeding. Entergy Texas sought Commission approval to update its GCRR under PURA § 36.214 and 16 TAC § 25.248(h) to recover a return of and on its actual capital investment in the Montgomery County power station.

30. In the update application, the proposed updated GCRR was designed to recover Entergy Texas's Montgomery County power station-related net generation invested capital incurred through January 31, 2021, and amounts associated with Entergy Texas's return on net generation invested capital, depreciation, federal income taxes, and other taxes.

31. Entergy Texas proposed that the updated GCRR take effect on January 1, 2021, the date identified by Entergy Texas as the date the Montgomery County power station began providing service to Entergy Texas's customers.

32. The update application was filed within 60 calendar days after January 1, 2021, the date identified by Entergy Texas as the date the Montgomery County power station began providing service to Entergy Texas's customers.

33. At the time the update application was filed, Entergy Texas's proposed sale of a 7.55% interest in the Montgomery County power station to ETEC was still subject to either Commission approval or denial in Docket No. 50790. In the update application, Entergy Texas proposed alternative GCRR revenue requirements and rate schedules to account for either potential outcome in Docket No. 50790.

34. Entergy Texas stated in the update application that if the Commission approved the proposed sale to ETEC in accordance with an unopposed agreement in Docket No. 50790 (the sale scenario), Entergy Texas would own 100% of the Montgomery County power station until the sale closes and then 92.45% of the facility thereafter. Entergy Texas stated that the sale scenario would result in a total updated GCRR revenue requirement of approximately $88.5 million on an annual basis.

35. Entergy Texas stated in the update application that if the Commission rejected the unopposed agreement and denied the proposed sale to ETEC in Docket No. 50790 (the no-sale scenario), Entergy Texas would retain its 100% ownership of the Montgomery County power station. Entergy Texas stated that the no-sale scenario would result in a total updated GCRR revenue requirement of approximately $95.7 million on an annual basis.

36. In the update application, Entergy Texas also proposed to file in this docket, as soon as reasonably practicable after the approval of its updated GCRR, a relate-back rider tariff that includes a revenue requirement reflecting carrying costs on the incremental portion of its Montgomery County power station generation invested capital (i.e., the portion incurred since August 31, 2020) from January 1, 2021 through the date Entergy Texas's updated GCRR rates are approved in this proceeding. Entergy Texas stated that its proposed relate-back rider would give effect to the requirements in PURA § 36.214(d) and 16 TAC § 25.248(h). Entergy Texas also provided a tariff and illustrative calculations of its relate-back-rider revenue requirement and rates under the sale scenario.

37. In the update application, Entergy Texas sought Commission approval of only the proposed form of the relate-back rider tariff, including its term, and the methodology used to calculate its revenue requirement and rates. Entergy Texas proposed, in a subsequent filing in this docket, to update the proposed relate-back rider's revenue requirement and rates to reflect the carrying costs consistent with the timing of the approved date of Entergy Texas's updated GCRR.

38. In Order No. 10 filed on April 16, 2021, the Commission administrative law judge (ALJ) unabated this proceeding.

39. In Order No. 11 filed on May 3, 2021, the Commission ALJ found the update application sufficient for further review.

40. On May 11, 2021, Entergy Texas filed an amendment to the update application. In the amendment, Entergy Texas stated that the Commission approved the sale of a partial interest in the Montgomery County power station in Docket No. 50790 and that the sale was expected to close on June 4, 2021.

41. In the amended update application, Entergy Texas stated that the updated GCRR would reflect the sale scenario, in which Entergy Texas would own 100% of the Montgomery County power station until the sale of the partial interest closed and then a reduced interest thereafter. Entergy Texas also stated that, based on the results of final performance testing, the 75 megawatts to be sold to ETEC actually constitute a 7.56% interest in the Montgomery County power station, which results in a $9,577 reduction in the sale-scenario revenue requirement presented in the update application filed on March 2, 2021. In addition, Entergy Texas updated the revenue requirement and rates of the illustrative relate-back rider to account for the expected June 4, 2021 closing date of the partial sale to ETEC and to reflect the removal of depreciation expense attributed to ETEC's purchase of the partial interest to ensure there is no double recovery of depreciation expense.

Notice

42. On October 5, 2020, Entergy Texas notified all parties to its last base-rate proceeding, Docket No. 48371,[6] that the initial application was filed. The notice was mailed by first-class mail the same day the application was filed, specified the docket number assigned to the application, and included a copy of the application.

43. On October 6, 2020, Entergy Texas filed the affidavit of Sarah K. Merrick, senior paralegal in the Austin office of Eversheds Sutherland (US) LLP, testifying to the provision of notice as described in finding of fact 42.

44. In Order No. 2 filed on October 16, 2020, the Commission ALJ found the notice of the October 5, 2020 application sufficient.

[6] *Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates*, Docket No. 48371, Order (Dec. 20, 2018).

45. On March 2, 2021, Entergy Texas notified all parties to its last base-rate case that the update application was filed. The notice was mailed by first-class mail the same day the update application was filed, specified this docket number, and included a copy of the update application.

46. On March 17, 2021, Entergy Texas filed the affidavit of Ms. Merrick testifying to the provision of notice of the update application as described in finding of fact 45.

47. In Order No. 11 filed on May 3, 2021, the Commission ALJ found the notice of the March 2, 2021 update application sufficient.

Intervenors

48. Motions to intervene were filed by the Office of Public Utility Counsel (OPUC), Texas Industrial Energy Consumers (TIEC), and the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange (collectively, Cities).

49. In Order No. 2 filed on October 16, 2020, the Commission ALJ granted all of the motions to intervene.

Pre-filed Testimony and Statements of Position

50. In support of the October 5, 2020 initial application, Entergy Texas filed the direct testimonies of Abigail Weaver, Richard Lain, Ms. Lofton, Mr. Dickens, and Kristin Sasser.

51. On December 7, 2020, the following direct testimonies addressing the October 5, 2020 initial application were filed by intervenors: the direct testimony of TIEC witness Jeffry C. Pollock; the direct testimony of OPUC witness Constance T. Cannady; and the direct testimony of Cities witness Karl J. Nalepa.

52. On December 16, 2020, Entergy Texas filed the testimony of Ms. Lofton in support of the December 16, 2020 agreement, and Commission Staff filed the testimony of Reginald Tuvilla in support of that agreement.

53. In support of the update application filed on March 2, 2021, Entergy Texas filed the update testimonies of Ms. Weaver, Mr. Lain, Ms. Lofton, Mr. Dickens, and Ms. Sasser.

54. On May 11, 2021, Entergy Texas filed the supplemental update testimonies of Ms. Lofton and Mr. Lain in support of the amendment to the update application.

55. On May 18, 2021, OPUC filed comments on the merits of the update application.

56. On October 13, 2021, Entergy Texas filed the testimony of Ms. Lofton in support of the October 13, 2021 agreement, and Commission Staff filed the testimony of Mark Filarowicz in support of the agreement.

Requests for Hearing

57. On November 9, 2020, OPUC, Cities, and TIEC filed requests for a hearing on the October 5, 2020 initial application.

58. On December 4, 2020, the Commission ALJ filed notice setting a hearing on the merits for the October 5, 2020 initial application to take place on December 17 and 18, 2020.

59. In Order No. 5 filed on December 9, 2020, the Commission ALJ cancelled the hearing on the merits for the October 5, 2020 initial application.

60. On May 18, 2021, Cities and TIEC filed requests for a hearing on the March 2, 2021 update application.

61. On June 1, 2021, Commission Staff filed a request for referral to the State Office of Administrative Hearings (SOAH) for an evidentiary hearing on the update application.

Referral to SOAH

62. On June 10, 2021, the Commission referred this proceeding to SOAH.

63. On June 24, 2021, the Commission filed a preliminary order.

64. In SOAH Order No. 2 filed on July 7, 2021, the SOAH ALJ established a procedural schedule including setting a hearing on the merits of the update application to convene on September 14, 2021.

65. In SOAH Order No. 3 filed on July 30, 2021, the SOAH ALJ abated the procedural schedule at the parties' request.

66. In SOAH Order No. 5 filed on October 14, 2021, the SOAH ALJ admitted evidence, dismissed the proceeding from the SOAH docket, and remanded the proceeding to the Commission.

The Agreement

67. On October 13, 2021, Entergy Texas filed an agreement executed by Entergy Texas, Commission Staff, OPUC, and TIEC resolving the issues between the parties to this proceeding. The only other party to this proceeding, Cities, is not a signatory to the agreement but does not oppose its terms.

68. The signatories agreed that the updated GCRR rates will be set based on the power generation facility net invested capital for the Montgomery County power station, using the sale scenario, reflecting costs incurred before January 1, 2021, as shown in exhibit A to the agreement. Entergy Texas reserved the right to request recovery of Montgomery County power station-related costs incurred on or after January 1, 2021 in a future base-rate proceeding.

69. Under the agreement, Entergy Texas will recover \$88,284,019 annually under its GCRR. The amount includes a \$54,305,707 return on rate base; depreciation expense of \$18,416,494; federal income tax expense of \$9,501,412; and taxes other than income of \$6,060,407.

70. The agreed-to \$54,305,707 return on rate base represents a 7.73% return on Entergy Texas's net power generation facility net invested capital of \$702,971,456. The Commission approved a 7.73% rate of return in Entergy Texas's last base-rate proceeding, Docket No. 48371.

71. The signatories agreed that the updated GCRR rates comply with all the terms contained in the December 16, 2020 agreement.

72. The signatories agreed that the updated GCRR revenue requirement and rates included in exhibit A to the agreement should be approved by the Commission.

73. The signatories agreed that the updated GCRR tariff included as exhibit B to the agreement should be approved by the Commission.

74. The agreement provides an effective date of January 1, 2021 for the updated GCRR tariff.

75. Under the updated GCRR tariff attached to the signatories' agreement as exhibit B, Entergy Texas's charges by rate class are as follows.

Rate Class	**GCRR Rate**
Residential Service	$0.006776 per kWh
Small General Service	$0.005629 per kWh
General Service	$1.408 per kW
Large General Service	$1.738 per kW
Large Industrial Power Service	$1.415 per kW
Lighting Service	$0.002757 per kWh

76. The updated GCRR rates approved by this Order are just and reasonable.

77. The signatories agreed that the GCRR relate-back rates will reflect the sale of the 7.56% partial interest in the Montgomery County power station to ETEC on June 4, 2021.

78. The signatories agreed that Entergy Texas will file a final relate-back rider tariff in this docket as soon as practicable after the approval of the updated GCRR that is consistent with the form and methodology used to calculate the rider's revenue requirement and rates as proposed in the update application as amended and based on costs incurred before January 1, 2021. Subject to the terms of the agreement, the signatories reserved the right to review and, if necessary, contest the relate-back rider tariff to the extent any signatory asserts that the rates reflected were not calculated in accordance with the form and methodology approved by this Order.

Interim Rates

79. In the interim order filed on January 20, 2021, the Commission approved Entergy Texas's GCRR rates on an interim basis, effective with usage on and after January 1, 2021.

80. In its order filed on July 30, 2021 in Docket No. 51557, the Commission approved GCRR rates identical to the rates approved on an interim basis in this docket effective with usage on and after June 5, 2021, subject to the Commission's final order in this docket.

81. The GCRR rates approved by this Order reflect Entergy Texas's net generation invested capital in the Montgomery County power station incurred before January 1, 2021, in the amount of $702,971,456, and amounts associated with Entergy Texas's return on net generation facility invested capital, depreciation, federal income taxes, and other taxes.

Evidentiary Record

82. In Order No. 6 filed on December 17, 2020, the Commission ALJ admitted the following evidence relating to Entergy Texas's initial application:

    a. Entergy Texas's initial application, including all attachments, filed on October 5, 2020;

    b. the direct testimonies and exhibits of Entergy Texas witnesses Ms. Weaver, Mr. Lain, Ms. Lofton, Mr. Dickens, and Ms. Sasser, filed on October 5, 2020;

    c. Entergy Texas's proof of notice filed on October 6, 2020;

    d. the direct testimony and exhibits of TIEC witness Mr. Pollock, OPUC witness Ms. Cannady, and Cities witness Mr. Nalepa, filed on December 7, 2020;

    e. the testimony, exhibits, and schedules of Entergy Texas witness Ms. Lofton and the testimony of Commission Staff witness Reginald Tuvilla in support of the December 16, 2020 agreement, filed on December 16, 2020; and

    f. the agreement, including its attachments, filed on December 16, 2020.

83. In Order No. 7 filed on January 7, 2021, the Commission ALJ admitted the affidavit of Mr. Dickens filed on January 4, 2021.

84. In SOAH Order No. 5 filed on October 14, 2021, the SOAH ALJ admitted the following evidence relating to Entergy Texas's update application:

    a. Entergy Texas's update application, including all attachments, filed on March 2, 2021;

    b. the update testimonies and exhibits of Entergy Texas witnesses Ms. Weaver, Mr. Lain, Ms. Lofton, Mr. Dickens, and Ms. Sasser, filed on March 2, 2021;

    c. Entergy Texas's proof of notice, filed on March 17, 2021;

d. Entergy Texas's amendment to the update application, including all attachments, filed on May 11, 2021;

e. the supplemental update testimonies and exhibits of Entergy Texas witnesses Mr. Lain and Ms. Lofton, filed on May 11, 2021;

f. the affidavit of Mr. Wilcox, filed June 18, 2021;

g. the agreement, including its attachments, filed on October 13, 2021; and

h. the testimony and exhibit of Entergy Texas witness Ms. Lofton and the testimony of Commission Staff witness Mr. Filarowicz, in support of the October 13, 2021 agreement.

Informal Disposition

85. More than 15 days have passed since the completion of notice provided in this docket.

86. No person filed a protest.

87. Entergy Texas, Commission Staff, OPUC, Cities, and TIEC are the only parties to this proceeding.

88. No hearing is necessary.

89. All parties to this proceeding are either signatories to the agreement or did not oppose the agreement.

90. The decision is not adverse to any party.

II. Conclusions of Law

The Commission makes the following conclusions of law.

1. Entergy Texas is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

2. As an electric utility that operates solely outside of the ERCOT region, Entergy Texas may request to recover investment in a power generation facility through a GCRR outside of a base-rate proceeding under PURA § 36.214 and 16 TAC § 25.248.

3. The Commission has authority over this matter under PURA §§ 14.001, 32.001, 36.001, and 36.214.

4. This docket was processed in accordance with the requirements of PURA, the Administrative Procedure Act,[7] and Commission rules.

5. SOAH exercised jurisdiction over this proceeding in accordance with PURA § 14.053 and Texas Government Code § 2003.049.

6. Within 60 days after the Montgomery County power station began providing service to Entergy Texas's customers, Entergy Texas filed its application to update its GCRR to reflect its actual capital investment in the Montgomery County power station in compliance with 16 TAC § 25.248(g)(5).

7. Entergy Texas provided notice of the applications in accordance with 16 TAC § 25.248(g)(2).

8. Entergy Texas's initial application is sufficient under 16 TAC § 25.248(g).

9. Entergy Texas's update application is sufficient under 16 TAC § 25.248(g) and (h).

10. The hearing on the merits for the initial application was set, and notice of the hearing was given, in compliance with Texas Government Code §§ 2001.051 and 2001.052.

11. The hearing on the merits for the update application was set in compliance with Texas Government Code §§ 2001.051 and 2001.052.

12. The rates approved by this Order are just and reasonable under PURA § 36.003(a).

13. In accordance with PURA § 36.003(b), the rates approved by this Order are not unreasonably preferential, prejudicial, or discriminatory and are sufficient, equitable, and consistent in application to each class of customers.

14. The rates approved by this Order were calculated in compliance with 16 TAC § 25.248(d).

[7] Tex. Gov't Code §§ 2001.001-.903.

15. The rates approved by this Order were calculated using the rate of return approved by the Commission in Entergy Texas's last base-rate proceeding, Docket No. 48371, in accordance with 16 TAC § 25.248(d)(5)(C)(iii).

16. The rates approved by this Order were calculated using the baseline jurisdictional and rate-class allocation factors used to allocate generation invested capital in Entergy Texas's last base-rate proceeding, Docket No. 48371, in accordance with 16 TAC § 25.248(e).

17. For the purposes of establishing the rates approved by this Order, Entergy Texas's customers were classified according to the rate classes established in Entergy Texas's most recently completed base-rate proceeding, Docket No. 48371, in accordance with 16 TAC § 25.248(f).

18. Under 16 TAC § 25.248(i), the amounts Entergy Texas recovers under the GCRR approved by this Order are subject to reconciliation in the first base-rate proceeding for Entergy Texas that is filed after the effective date of the GCRR approved by this Order. As part of the reconciliation, the Commission will determine if the amounts recovered under the approved GCRR are prudent, reasonable, and necessary.

19. Under PURA § 36.214(f) and 16 TAC § 25.248(j), an electric utility must initiate a base-rate proceeding at the Commission not later than 18 months after the date its GCRR takes effect if the GCRR includes incremental recovery for a power generation facility or power generation facilities and the amount of generation invested capital is greater than $200 million on a Texas jurisdictional basis.

20. The approved GCRR includes incremental recovery for a power generation facility where the amount of generation invested capital is greater than $200 million on a Texas jurisdictional basis. Accordingly, Entergy Texas is required to initiate a base-rate proceeding no later than 18 months after the effective date of the GCRR approved by this Order.

21. The requirements for informal disposition under 16 TAC § 22.35 have been met in this proceeding.

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders.

1. The Commission authorizes Entergy Texas to update its GCRR to the extent provided in this Order.

2. The Commission approves the updated GCRR tariff included as exhibit B to the October 13, 2021 agreement, effective with usage on and after January 1, 2021.

3. The Commission does not determine in this Order whether the investments recovered through the approved GCRR comply with PURA or are prudent, reasonable, and necessary. The Commission will make those determinations in Entergy Texas's future base-rate proceeding.

4. As part of Entergy Texas's next base-rate proceeding, Entergy Texas must request to move all investment being recovered in its GCRR into base rates and to set its GCRR to zero.

5. Within ten days of the date of this Order, Entergy Texas must file a clean copy of the updated GCRR tariff, included as exhibit B to the October 13, 2021 agreement, with the approved effective date, with central records to be marked *Approved* and kept in the Commission tariff book.

6. The Commission approves the form and methodology of the relate-back rider as proposed in the update application as amended, including its five-month term.

7. As soon as reasonably practicable, Entergy Texas must file a relate-back rider tariff that is consistent with the form and methodology used to calculate the rider's revenue requirement and rates as proposed in the update application as amended. The relate-back rider must be filed in a new proceeding.

8. Entergy Texas must initiate a base-rate proceeding at the Commission no later than 18 months after January 1, 2021.

9. Entry of this Order does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the agreement and must not be regarded as

precedential as to the appropriateness of any principle or methodology that may underlie the agreement.

10. The Commission denies all other motions and any other requests for general or specific relief, if not expressly granted.

Signed at Austin, Texas the 14th day of January 2022.

PUBLIC UTILITY COMMISSION OF TEXAS

PETER M. LAKE, CHAIRMAN

WILL MCADAMS, COMMISSIONER

JIMMY GLOTFELTY, COMMISSIONER

W2013
q:\cadm\orders\final\51000\51381 fo.docx

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Second Set of Data Requests	Prepared By: Omar El Shal Sponsoring Witnesses: Anastasia R. Meyer, Beverley Gale
of Requesting Party: Texas Industrial Energy Consumers	Beginning Sequence No. LR861 Ending Sequence No. LR862

Question No.: TIEC 2-2 Part No.: Addendum:

Question:

Please provide any analyses and documents supporting a 30-year lifespan for Montgomery County Power Station (MCPS).

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

The determination to adopt a 30-year lifespan assumption for Montgomery County Power Station ("MCPS") is derived from Mitsubishi's position on the lifespan of its combined cycle units, as well as a collection of reputable industry resources, such as the Electric Power Research Institute ("EPRI"), combined with Entergy's experience with owning and operating natural gas plants.

Please see the highly sensitive attachment (TP-53719-00TIE002-X002-001_HSPM), a technology summary prepared by EPRI, which highlights the assumption for a 30-year lifespan of the MHI M501GAC.

Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Second Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Omar El Shal Sponsoring Witness: Anastasia R. Meyer Beginning Sequence No. LR867 Ending Sequence No. LR867

Question No.: TIEC 2-3 Part No.: Addendum:

Question:

Please provide any documents comparing the lifespans of combined cycle gas turbine plants installed in the past ten years.

Response:

The Company has not conducted nor is aware of any comparisons of the life spans of combined cycle gas turbine plants installed the past ten years; therefore, the Company does not have any documents responsive to this request. However, in the last ten years, the Entergy Operating Companies have built a total of four combined cycle gas turbine plants (Ninemile 6, J. Wayne Leonard, Lake Charles, and Montgomery County), all of which are assumed to have 30-year life spans. The operating performance (*e.g.*, reliability and plant utilization) of each plant has been and continues to be consistent with this assumption.

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

JASON A. CASH

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

OCTOBER 2020

TESTIMONY INDEX

EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT JAC-1	Rate Case Experience of Jason A. Cash
EXHIBIT JAC-2	Depreciation Study Report
EXHIBIT JAC-3	Depreciation Study Work Papers (CD)

(These Work Papers are voluminous and are provided on a CD)

SOUTHWESTERN ELECTRIC POWER COMPANY
SCHEDULE IV - Generating Unit Retirement Dates
December 31, 2019

Station & Unit	Capability MW	Year Installed	Estimated Year Retired	Life Span (Years)
GAS & OIL UNITS				
Arsenal Hill				
Unit 5	110	1960	2025	65
Knox Lee				
Unit 5	342	1974	2039	65
Lieberman				
Unit 3	109	1957	2022	65
Unit 4	108	1959	2024	65
Mattison				
Unit 1	76	2007	2052	45
Unit 2	76	2007	2052	45
Unit 3	76	2007	2052	45
Unit 4	76	2007	2052	45
Stall				
Unit 6	500	2010	2050	40
Wilkes				
Unit 1	177	1964	2029	65
Unit 2	362	1970	2035	65
Unit 3	362	1971	2036	65
COAL & LIGNITE UNITS				
Dolet Hills (1)				
Unit 1	262	1986	2021	35
Flint Creek				
Unit 1	264	1978	2038	60
Pirkey				
Unit 1	580	1985	2045	60
Turk				
Unit 1	440	2012	2067	55
Welsh				
Unit 1	528	1977	2037	60
Unit 3	528	1982	2042	60

Notes:
(1) The recovery of the Dolet Hills Power Station is being addressed outside of the depreciation study.

DOCKET NO. 53719

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

BEVERLEY GALE

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

owning each plant. As such, ETI employees operate and maintain Sabine, Lewis Creek, and MCPS on a day-to-day basis and provide the necessary on-site management, while ESL employees provide oversight in operational, financial and administrative functions supporting Power Generation.

The ESL employee groups in Power Generation are staffed by trained and experienced personnel who provide executive and management oversight, compliance, support, planning and training services, environmental and safety support, fleet maintenance, plant support, and other services necessary for the efficient and effective operation and maintenance of ETI's plants as well as those plants owned and operated by the other EOCs. This organizational structure allows those support activities that are common to all plants to be shared by the EOCs, thereby reducing the overall cost to each EOC through a more efficient utilization of the staff. The Power Generation organization has been designed to avoid duplication of functions, activities, and responsibilities among ESL employees and those of the EOCs, including ETI. Power Generation operates as a single, integrated organizational unit.

Q9. HOW IS POWER GENERATION ORGANIZED?

A. My Exhibit BG-1 contains an organizational chart for Power Generation, for the Test Year, which indicates the functional groups that report to the Vice President of Power Generation. The geographic/jurisdictional structure of Power Generation is organized by four different jurisdictions of the EOCs: Texas, Louisiana (including New Orleans), Mississippi, and Arkansas. I am responsible for Texas.

Q10. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE FACILITIES OWNED BY ETI.

A. ETI's fleet consist of the following power plants: Nelson Unit 6; Big Cajun II Unit 3; Lewis Creek; Sabine; Hardin County; and MCPS.

- Nelson Unit 6 is a coal unit (524 MW) located at Westlake, Louisiana, just outside of Lake Charles, Louisiana. ETI owns 29.75% (156 MW) of the unit, which is operated and maintained by ELL. The remaining ownership percentages are as follows: ELL owns 40.25% (211 MW); EAM Nelson Holdings owns 10.9% (57 MW);[2] Sam Rayburn G&T, Inc. owns 10% (52 MW); and East Texas Electric Cooperative, Inc. ("ETEC") owns 9.1% (48 MW).
- The Lewis Creek Plant is located at Willis, Texas, north of Conroe, Texas (near Lake Conroe), and consists of two gas-fired units (510 MW total) owned and operated by ETI.
- The Sabine Plant is located at Bridge City, Texas, on the north shore of Sabine Lake in southeast Texas and consists of four gas-fired units (1643 MW total) owned and operated by ETI. The Sabine Plant also manages oversight of a third-party that operates the Spindletop Gas Storage Facility (and pipeline system) and the Hardin County Facility. Spindletop is a gas storage facility that provides emergency fuel supply to the Sabine Power Plant. The facility consists of two salt dome gas storage caverns, cavern withdrawal operations and leaching operations.
- Hardin County facility is located near the City of Kountze in Hardin County, Texas and is comprised of two combustion turbine generation units (157 MW), which is operated by Ethos Energy Power Plant Services, LLC. This facility provides ETI with incremental capacity to help address its overall capacity needs and specifically its peaking and reserve capacity needs.
- Big Cajun II, Unit 3 (557 MW) is a coal unit located in New Roads, Louisiana, on the Mississippi River north of Baton Rouge, Louisiana. The unit is operated and maintained by Louisiana Generating L.L.C., which

[2] EAM Nelson Holdings is a wholly owned un-regulated subsidiary of Entergy Asset Management/Entergy Corp.

owns 58% (323 MW) of the unit. ETI owns 17.85% (99 MW) and ELL owns 24.15% (135 MW) of the unit.

- MCPS is located near Willis, Texas adjacent to the Lewis Creek generation facility. It is a 993MW power station that uses new technology to provide ETI and its customers a cleaner and more efficient source of power. The MCPS CCGT facility consists of two Mitsubishi Hitachi Power Systems ("MHPS") 501 GAC-series combustion turbines, two Nooter Eriksen heat recovery steam generators ("HRSG") with duct firing, one Toshiba steam turbine generator in a 2x1 combined cycle configuration, and other balance of plant equipment, including a cooling tower for closed-cycle cooling operations. The ETI operates this unit and owns 92.44% (972MW), and ETEC owns a 7.56% (73 MW) interest in the unit.

ETI's generating units are listed in Exhibit BG-2 with additional information regarding each unit. Exhibit BG-2 uses winter capacity ratings as of December 31, 2021. Further information concerning each of ETI's operating units is provided in Schedule H-12.3b.

Q11. IN ADDITION TO THE PLANTS YOU DESCRIBED ABOVE, DOES ETI PLAN CONTINUED INVESTMENT IN ITS GENERATION FLEET TO ENSURE RELIABLE AND REASONABLY PRICED POWER FOR ITS CUSTOMERS?

A. Yes. Currently, ETI is requesting authority from the Commission to build Orange County Advanced Power Station ("OCAPS") in the pending Docket No. 52487. OCAPS is a foundational component of ETI's resource adequacy and fleet modernization plan. OCAPS will provide 1,215 MW of modern, dispatchable generation in Texas to help meet the resource needs of ETI's customers in a reliable and economic manner, support and promote the Southeast Texas economy, and best position customers for the future. Importantly, OCAPS will replace roughly 1,100 MW of aging capacity at ETI's Sabine generation site, where OCAPS will be located. In addition to being the most efficient generator in ETI's fleet, OCAPS will be capable of co-firing 30% hydrogen by volume and thus provide an opportunity for a significant amount of clean, dispatchable energy. OCAPS's dual fuel capability and ability to use ETI's Spindletop fuel storage facility will provide significant and sustainable economic and reliability benefits to ETI customers. ETI is planning to invest approximately $895 million in generation capital in 2022-2024, of which OCAPS is a significant part.

Q12. CAN THE ETI GAS UNITS BURN FUEL OIL AS A SECONDARY FUEL?

A. ETI's gas units are not functionally capable of burning fuel oil as a secondary fuel. A small amount of fuel oil is used at Sabine Unit 5 for ignitors.

Q13. DO NELSON UNIT 6 AND BIG CAJUN II, UNIT 3 BURN FUEL OIL?

A. Yes. It is necessary for both coal units to burn a small amount of No. 2 fuel oil as an ignitor and warm-up fuel. The ignitors are used to light the coal burners and to provide flame stabilization during startups and shutdowns. In addition, No. 2 fuel oil is used during unit startups to warm up the boiler and to increase boiler pressure prior to switching to coal (refer to Schedule H-12.3b "Nelson 6 and Big Cajun II No. 3 boiler" sections).

Q20. HAS ETI RECENTLY MADE A DECISION TO CHANGE THE DEACTIVATION DATES FOR CERTAIN GENERATING UNITS?

A. Yes. As discussed in more detail below, the deactivation date assumption for Nelson 6 has changed from [redacted], and Big Cajun 2 Unit 3 has changed from [redacted]. ETI also recently made a deactivation decision for Sabine 1 to extend the deactivation date from 2022 to May 31, 2023, to align with the transfer of the existing transmission rights at the site to the new proposed Orange County Advanced Power Station ("OCAPS"), as discussed in more detail below.

Q21. HOW WILL THE AGE OF NELSON 6 AND BIG CAJUN 2 UNIT 3 AT THEIR PROPOSED DEACTIVATION DATES COMPARE TO THE INDUSTRY AVERAGE?

A. As shown in Exhibit ARM-2, these units will be over 40 years old by their assumed deactivation dates. Figure 1 below shows an average retirement age of 42.4 years for coal-fired generating capacity greater than 400 MW. Nelson 6's age at deactivation of [redacted] years exceeds the average, while Big Cajun 2 Unit 3's age of [redacted].

Figure 1: Generator Age at Retirement[6]

Thus, the changes to the deactivation dates for Nelson 6 and Big Cajun 2 Unit 3 represent a reasonable expected useful life for these resources.

A. <u>Nelson 6</u>

Q22. PLEASE DESCRIBE NELSON 6.

A. Nelson 6 is Unit 6 of the Roy S. Nelson Generating Plant. Nelson 6 is a 521.4 MW[7] coal-fired power station in Westlake, Louisiana located within the West of the Atchafalaya Basin ("WOTAB") load pocket. Nelson 6 is jointly owned by ETI (29.8%), ELL (40.25%), EAM Nelson Holding, LLC. (10.9%), Sam Rayburn G&T, Inc. (10%) and ETEC (9.1%). Nelson 6 went into service in 1982 and is currently 40 years old. It is my understanding that since Cleco Power and Southwestern Electric Power Company ("SWEPCO") shut down the Dolet Hills

[6] This figure is from my workpapers.

[7] Unit capacity based on Generation Verification Test Capacity for MISO Planning Year 2022-2023 (June 1, 2022 through May 31, 2023).

Power Station east of Mansfield at the end of 2021 at 36 years of operation, Nelson 6 and Big Cajun 2 are the only two coal power plants left in Louisiana.[8]

Q23. PLEASE PROVIDE THE ENVIRONMENTAL COMPLIANCE COSTS ASSOCIATED WITH CONTINUING TO OPERATE NELSON 6.

A. Based on an assessment of the EPA's Regional Haze Program, the Company expects that it would be required to invest in sulfur dioxide ("SO_2") emission reduction technology ranging from approximately \$108.8 million to \$473.8 million (in 2019 dollars) in capital costs alone if the facility operated into the 2030s.[9] The Company estimates capital costs ranging from approximately \$12.2 million to \$172.3 million (in 2019 dollars) for nitrogen oxides ("NO_X") emission reduction options.[10] Significant investment in the aging facility, such as repowering it to gas, is not expected to be prudent and would likely increase the costs to customers. Due to the age of the unit, the year over year capital and operations & maintenance ("O&M") expenses to maintain Nelson 6, and the heightened scrutiny of coal-generating units by regulatory agencies (and the increased costs associated with additional regulations and compliance), the Company conducted an economic analysis to determine whether it would be more

[8] Kristen Mosbrucker, *One of the Last Coal-Fired Power Plants in Louisiana to Close, Laying off Dozens*, The Advocate, Oct. 28, 2021, available at: https://www.theadvocate.com/baton_rouge/news/business/article_190562bc-3824-11ec-bcfa-239aa1f91d40.html.

[9] *See* Response to March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request, Entergy Services LLC on behalf of Entergy Louisiana LLC, Roy S. Nelson Electric Generating Plant at Table 2-3 (July 30, 2020) available at https://edms.deq.louisiana.gov/app/doc/view?doc=12280842 (providing the estimated costs for SO_2 emissions reduction options).

[10] *Id.* at Table 3-3.

cost-effective to deactivate the unit earlier than 2030.

Q24. PLEASE DESCRIBE THE ECONOMIC ANALYSIS AND THE RESULT.

A. EPG examined whether it would be more economic to build a new 372 MW generic combustion turbine ("CT") with hydrogen capabilities than to continue to infuse capital into an aging coal-fired generating unit subject to increased environmental compliance costs. Because ETI is currently short generation capacity, a CT replacement was conservatively used to assess whether it was economic to deactivate Nelson 6 earlier than 2030. EPG determined it would be more economic to retire Nelson 6 as early as [redacted]. However, because ETI continues to be short generation capacity even with its plan to add OCAPS by 2026,[11] ETI plans to continue operating Nelson 6 through [redacted] to provide it with an adequate opportunity to procure replacement capacity as it works to modernize its generation fleet. ETI changed Nelson 6's deactivation date assumption from [redacted]. The presentations summarizing the results of the analysis are provided in highly sensitive Exhibits ARM-3 and ARM-4.

B. <u>Big Cajun 2 Unit 3</u>

Q25. PLEASE DESCRIBE BIG CAJUN 2 UNIT 3.

A. Big Cajun 2 was Louisiana's first coal-fired station and is located near the Mississippi River in New Roads, Louisiana. Unit 3 is a coal-fired unit that

---

[11] *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Orange County Advanced Power Station*, Docket No. 52487 (pending).

generates 554.5 MW[12] and is jointly owned by Louisiana Generation, LLC (58%), ELL (24.15%), and ETI (17.85%). It is operated by Cleco Cajun LLC. Unit 3 went into service in 1983 and is currently 39 years old. As a minority owner, ETI has limited control over the ongoing operations and retirement of Unit 3.

Q26. HAS CLECO PUBLICLY COMMITTED TO DEACTIVATING BIG CAJUN 2 UNIT 3?

A. Yes. In response to a March 18, 2020 Regional Haze Four-Factor Analysis Information Collection from the Louisiana Department of Environmental Quality, Trinity Consultants prepared and submitted a report on behalf of Cleco Power, Cleco Cajun LLC, and Louisiana Generating, LLC (together, "Cleco").[13] In that report, dated July 24, 2020, Cleco committed to "retir[ing] Units 2 and 3 no later than December 31, 2032."[14]

Q27. COULD CLECO DEACTIVATE BIG CAJUN 2 UNIT 3 SOONER THAN 2032?

A. Yes. The report provides the estimated costs of implementing SO_2 and NO_x emission reduction technologies and the timing of such implementation. It estimates \$94.8 million in annual costs for Big Cajun 2 Unit 3 for SO_2 and NO_x

---

12 Unit capacity based on Generation Verification Test Capacity for MISO Planning Year 2022-2023 (June 1, 2022 through May 31, 2023).

13 Response to March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request, July 24, 2020, available at https://edms.deq.louisiana.gov/app/doc/view?doc=12280837.

14 *Id.* at 1-1.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Fourth Set of Data Requests	Prepared By: Olena Harvey Sponsoring Witnesses: Beverly Gale, Anastasia R. Meyer
of Requesting Party: Texas Industrial Energy Consumers	Beginning Sequence No. PI1957 Ending Sequence No. PI1957

Question No.: TIEC 4-9 Part No.: Addendum:

Question:

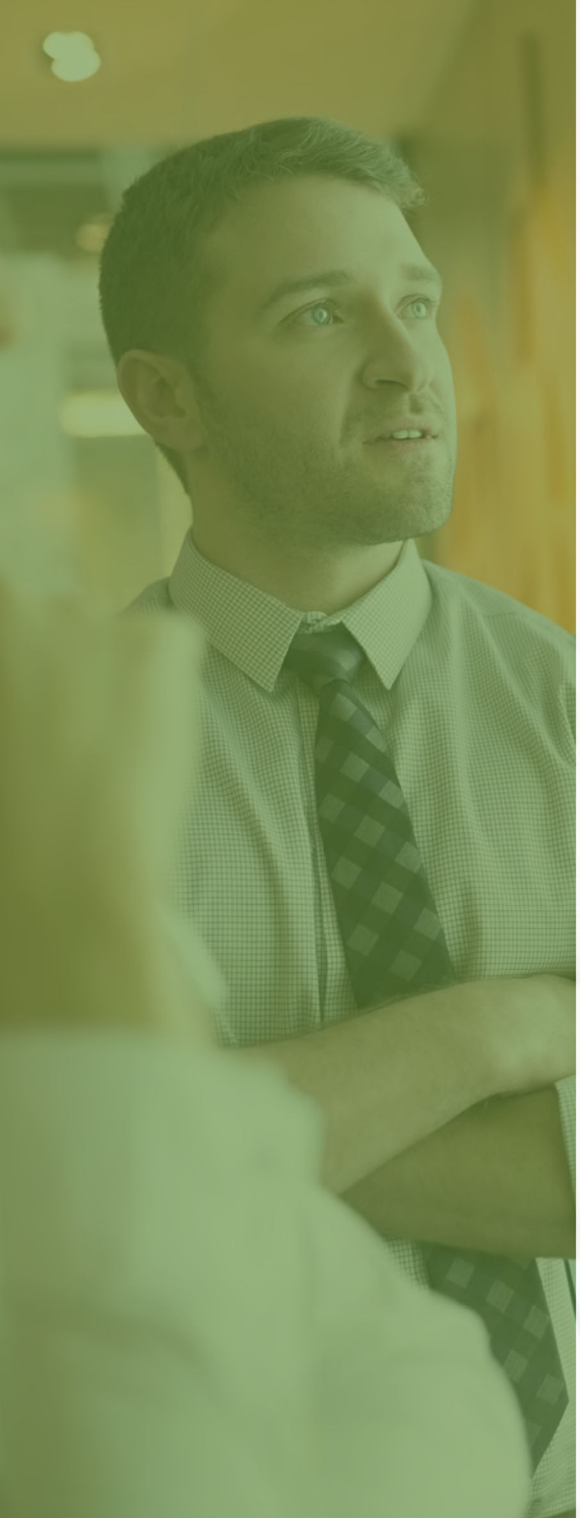
Please state whether ETI has advocated to any other entity that owns an interest in Nelson 6 or Big Cajun II Unit 3 for the retirement of Nelson 6 before [redacted] or of Big Cajun II Unit 3 before [redacted]

Response:

Entergy has made a public commitment to cease burning coal by 2030. The Company has not made any other public announcements, either for Nelson 6 or for Entergy's minority share of Big Cajun 2, Unit 3, besides this corporate commitment.

See also the Company's response to TIEC 4-7.

ENTERGY'S 2050 NET ZERO COMMITMENT



ENTERGY'S 2050 NET-ZERO COMMITMENT

This report provides an update on Entergy's continued portfolio transformation and outlines our commitment to achieve net-zero carbon emissions by 2050 while balancing affordability and reliability for our customers. This report serves as an addendum to our 2019 report, Climate Scenario Analysis and Evaluation of Risks and Opportunities. Establishing a net-zero by 2050 climate commitment continues Entergy's two decades of leadership and action on climate change described in detail in the 2019 climate report. We believe that an effective climate strategy should include a near-term goal and a long-term commitment, along with near-term actions supportive of these commitments.

In this addendum, we describe our commitment to achieving enterprise-wide net-zero carbon emissions by 2050, tangible near-term actions the company is taking toward meeting this commitment and our holistic vision of a net-zero future for the communities we serve. We also provide our view on technology developments and breakthroughs that may pave our path to net-zero emissions as described in an illustrative scenario of Entergy's evolving energy resource mix. Lastly, this addendum provides an overview of our three-phased approach to decarbonization over the five-decade span of 2000 to 2050 in the context of climate scenarios that limit warming to 1.5° to 2° Celsius.

Entergy's Commitment to Net-Zero Emissions by 2050

Entergy is committed to achieving net-zero emissions by 2050 while balancing affordability and reliability for our customers. We believe that the optimal net-zero strategy requires reduction of our own emissions as much as possible, followed by capturing or offsetting remaining emissions through various innovative strategies. Our decarbonization journey to net-zero ensures that our customers can reduce their environmental footprints by relying on our low-carbon generation fleet. Entergy views climate issues not only as a challenge to be addressed by the company and the communities and region that we serve, but also as an opportunity to invest in new technologies and customer solutions.

We take a holistic view of emission reductions. Given our unique role in the economy and our relationships with the customers and communities we serve, Entergy's commitment to net-zero is a critical part of ushering in a decarbonized economy, particularly in our region. As such, our near-term actions and long-term sustainability plans address the emissions profile of our generation portfolio while also considering partnerships with our customers and suppliers.

COMMITTED TO NET-ZERO EMISSIONS BY 2050

DECARBONIZE SUPPORT INFRASTRUCTURE AND SUPPLY CHAIN

CUSTOMER PARTNERSHIPS AND PRODUCTS

NET-ZERO

2050 Climate Commitment – Engaging Entergy's Full Value Chain

Holistic View of Decarbonization | All Emission Scopes | All Gases

Current Portfolio Transformation Technology:

- Retire coal-powered capacity
- Modernize gas assets
- Utility-scale renewables
- Energy storage (short-to-medium duration)
- Invest in and extend life of nuclear units
- Gas supply pipe upgrade and replacement
- Renewable energy credits and carbon offsets

Technology Developments and Future Options:

- New/advanced nuclear
- Carbon capture, utilization and sequestration
- Green/pink/blue hydrogen usage
- Renewable natural gas/alternative fuels
- Advanced renewables
- Energy storage (long duration)
- Advanced generation technology
- Incremental natural sequestration

Engage Customers & Other Sectors of the Economy:

- Energy efficiency
- Peak load reduction
- Demand-side management
- Customer solutions
- Distributed energy sources
- Beneficial electrification
- Gulf Coast Carbon Collaborative

Engage Suppliers:

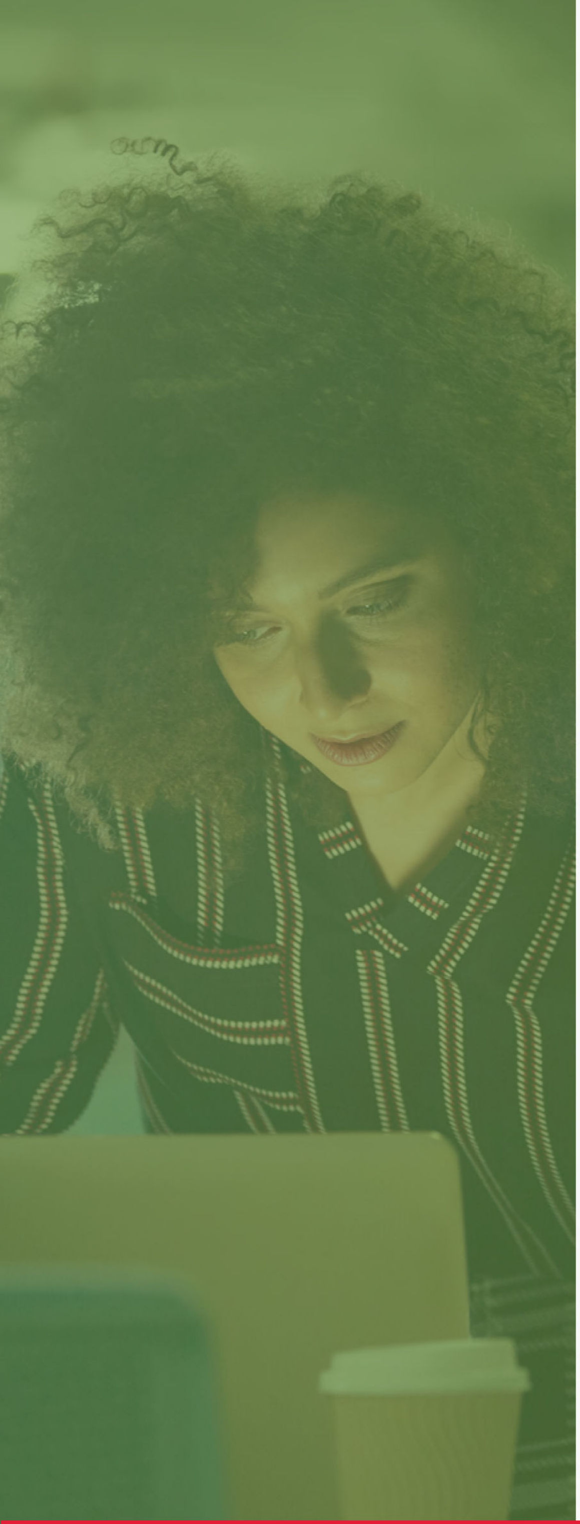
- Natural Gas Supply Collaborative – carbon impact of gas suppliers
- Electric Utility Industry Sustainable Supply Chain Alliance – carbon impact of non-fuel suppliers
- Renewable and H_2 collaborations
- Renewable natural gas
- Direct engagement with suppliers

Conventional Pollutant Reduction Goals

Entergy also anticipates significant reductions in conventional pollutants such as oxides of nitrogen (NOx), sulfur dioxide (SO_2) and mercury (Hg). We project that NOx and SO_2 both will be 90% below 2000 levels by 2030 and Hg emission will be near zero. As we move through our regular planning cycles, these projected reductions will be updated.

Committed to Net-Zero Emissions by 2050 – Entergy will continue to transform its generation portfolio to cleaner, low- and zero-carbon resources. This transformation will result in a lower emission rate as conceived by our 2030 climate analysis and goal. It also will result in reducing absolute emissions as additional low- and zero-carbon generation technologies are integrated into our system over the next three decades. In the illustrative scenario presented in this addendum, this transformation reduces Entergy's carbon emission rate by 90% from our base year, 2000.

Regarding Entergy's gas business, local distribution company operations represented only 0.2% of our direct emissions (fugitive losses – scope 1) and 2.4% of our indirect emissions (customer combustion – scope 3) in 2019. These categories are part of our net-zero commitment, and we will work to



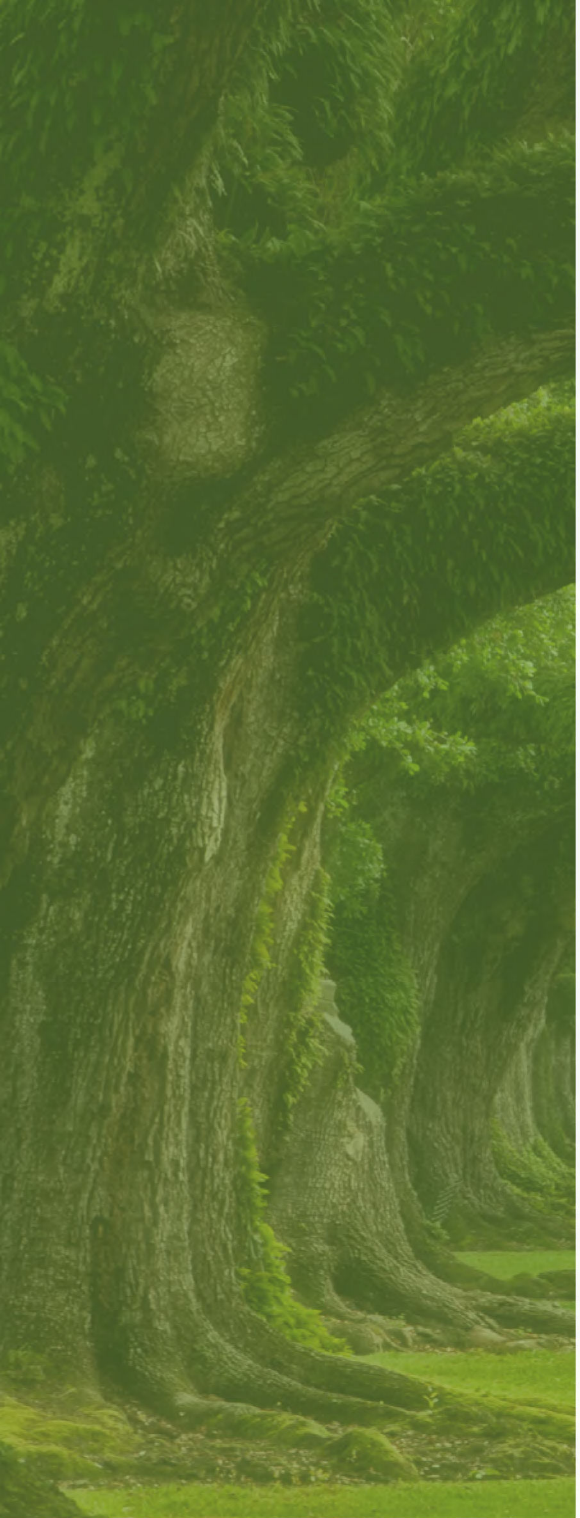
minimize these emissions through efforts to decarbonize the gas fuel supply, replace older supply piping and partner with customers on energy efficiency and beneficial electrification. Additionally, we will continue to engage our gas suppliers to reduce upstream emissions. All of these actions will minimize the full lifecycle emissions associated with these operations.

As we work to reduce emissions through technology solutions, Entergy also will continue its efforts to enhance natural, carbon-absorbing systems. As described in our 2019 climate report, the Paris Climate Agreement identifies the need to seek balance between sources of carbon and natural systems that absorb carbon. Over the last two decades, Entergy has gained valuable experience and supported innovations in the areas of reforestation/afforestation, wetland restoration and agricultural carbon offsets through our Environmental Initiatives Fund. We anticipate continuing and accelerating these actions that enhance natural systems to offset remaining carbon emissions and to improve the quality of life for customers and communities throughout our service area. Additionally, Entergy will account for the environmental attributes associated with renewable generation and natural gas owned and retired on behalf of the utility operating companies.

Customer Partnerships and Products – Entergy has identified an opportunity to engage with customers through various innovative offerings and partnerships that help reduce emissions for both our company and our customers. Entergy is working to expand energy efficiency and demand-side management offerings that reduce customer demand – while balancing the need to electrify carbon-intense energy needs in other sectors. Entergy's eTech program offers incentives to customers who are interested in electrification and is more fully described in the climate report.

In 2019, we shared thought leadership for the development of an economy-wide collaborative to reduce carbon. Entergy sponsored the December launch of the Gulf Coast Carbon Collaborative, which now provides an ongoing platform for regional collaboration on carbon reduction efforts across all sectors of the economy. Additionally, the company is evaluating opportunities for distributed generation solutions to supplement centralized generation resources and improve community resiliency. Our company is uniquely positioned to engage with our customers, many of whom also are setting aggressive climate goals and establishing business models around the opportunities for investing in many of the technologies discussed in this report.

Decarbonize Support Infrastructure and Supply Chain – We are engaging both fuel and non-fuel suppliers on decarbonizing the fuel supply and the various materials/goods we procure. We have joined the Natural Gas Supply Collaborative to engage fuel suppliers on upstream emissions associated with exploration, production and transportation. As a founding member of the Electric Utility Industry Sustainable Supply Chain Alliance, we engage broadly with suppliers of materials and goods to our sector. Additionally, some of our largest suppliers and customers are implementing low-carbon business models. We are engaged in partnerships focused on developing utility-scale renewable generation and the technology and infrastructure necessary to decarbonize our fuel supply through co-firing of green and/or blue hydrogen. We also anticipate opportunities to collaborate on renewable natural gas and other mutually beneficial technology advancements such as carbon capture.



Entergy's 2019 Climate Report

In March 2019, Entergy published a report titled Climate Scenario Analysis and Evaluation of Risks and Opportunities. The purpose of this report is threefold: (1) to continue Entergy's long history of engagement on climate change and management of the risks to our business; (2) to use scenario planning to analyze potential impacts on – and opportunities for – Entergy and the regional economies in which we operate; and (3) to inform and engage stakeholders on Entergy's current and ongoing processes for managing climate risk and evaluating future opportunities. The structure of the analysis and report was informed by the Recommendations of the Task Force on Climate-related Financial Disclosures. The analysis also informed the establishment of our fourth voluntary carbon goal – to reduce our utility generation asset emission rate to 50% of what it was in 2000 by 2030. Information on our earlier Environment 2020 commitment and performance can be found on entergy.com.

The climate report discussion on strategy, governance, risks, opportunities, metrics and targets remains reflective of our current position on climate issues. On the strategy front, we are continuing to evaluate options and refine our path toward meeting our 2030 goal. Our resource planners continue to evaluate technology options and operational decisions necessary to ensure that we meet this goal. Additionally, a multilevel working group is focused on ensuring all options are explored in order to find the pathway that provides reliable, affordable and sustainable energy to our customers. Since the climate report was published, we have announced several related projects and efforts that can be found in our Newsroom. Here are some highlights:

- August 2019 – Entergy New Orleans Adding 90 Megawatts of Renewable Energy to Its Portfolio
- December 2019 – Cross-Industry Gulf Coast Coalition to Tackle Carbon Emissions
- March 2020 – Lake Charles Power Station Achieves Commercial Operation
- April 2020 – Mississippi Public Service Commission Gives Green Light to 1,000-Acre Solar Farm
- April 2020 – Entergy Named 2020 Tree Line USA Utility by Arbor Day Foundation
- April 2020 – Arkansas Public Service Commission Approves Searcy Solar Project
- July 2020 – New Analysis Shows Momentum Building To Decarbonize The Power Sector
- August 2020 – Entergy Arkansas Plans Fourth Solar-generation Resource, Walnut Bend, Near Brinkley
- September 2020 – Entergy New Orleans Completes Louisiana's Largest Commercial Rooftop Solar Project
- September 2020 – Mitsubishi Power and Entergy to Collaborate and Help Decarbonize Utilities in Four States
- September 2020 – Entergy Commits to Achieving Net-Zero Carbon Emissions by 2050

The final section of our climate report is focused on Entergy's future. This addendum expands on Entergy's view of our ongoing portfolio transformation, developing technology options, our commitment to net-zero emissions by 2050 and our holistic vision of a net-zero emission economy for our region.

Entergy and Mitsubishi Power to Collaborate and Help Decarbonize Utilities in Four States

Entergy has engaged with Mitsubishi Power because of the company's demonstrated ability to provide innovative total solutions, leveraging multiple technologies to reach decarbonization goals. Mitsubishi Power is a first mover in hydrogen-enabled gas turbine and long- and short-term storage solutions.

Together, Entergy and Mitsubishi Power will focus on:

- Developing hydrogen-capable gas turbine combined cycle facilities.
- Advancing green hydrogen production, storage and transportation facilities.
- Creating nuclear-supplied electrolysis facilities with energy storage.
- Developing utility-scale battery storage systems.
- Enabling economic growth through partnerships with the Entergy utility customers.

NET ZERO

Entergy's Ongoing Portfolio Transformation

Continuing the company's portfolio transformation strategy, Entergy expects to meet its 2030 target using technology that exists today. Initiated in 2002, this strategy focuses on modernizing our gas generation fleet, investing in our existing nuclear fleet, integrating renewable resources and retiring older, less-efficient fossil units, including all of the company's coal-powered capacity. Low- to zero-carbon technology developments are necessary to continue reducing both our carbon emission rate per megawatt hour and our absolute carbon emissions to levels consistent with our 2050 net-zero commitment. To achieve this commitment, technology developments and continued innovation are assumed to play a major role in enabling the decarbonization of our generation fleet while balancing customer costs and reliability. Some perspectives on advanced technologies, their role in the future, and our efforts to monitor and develop them are presented below:

Customer-centric Solutions – At Entergy, our focus is not on any particular product or service, but instead on the customer. Our customers' goals and objectives drive our planning and operational processes. Reducing demand for energy is an effective way to approach avoiding emissions. Entergy offers customers various energy efficiency-related products, services and programs. Our customers also desire behind-the-meter energy solutions, such as distributed generation and energy storage, which we are committed to helping them identify and implement. Additionally, electrifying energy needs currently served by fossil fuels is a decarbonization strategy employed by many of our customers. We expect all these areas – energy efficiency, distributed generation/storage and electrification – to continue to develop over the next three decades. Entergy's goal is for these strategies to benefit our customers while also supporting our decarbonization strategy and enhancing economic performance.

Coal Generation Retirement – Entergy intends to cease burning coal by the end of 2030. Coal currently makes up only 6% of our generation, less than 5% of 2019 revenue and less than 2% of 2019 rate base. We do not anticipate constructing any future generation assets or securing power purchase agreements from any resources that use coal. Our employee commitment and community focus will continue to be important to Entergy as we transition from coal-powered capacity.

Natural Gas, Low-Carbon Fuels and Carbon Capture – We continue to modernize our gas generation fleet through our portfolio transformation strategy. Our analysis shows that natural gas units remain a necessary and economic resource to enable retirements of less-efficient gas units and to maintain system reliability as we transition to a low- to no-carbon economy. These modern, efficient gas units not only produce approximately 40% less carbon dioxide than older, less-efficient gas units, but we expect future gas generation to offer the option of co-firing advanced, lower- and zero-carbon fuels. Hydrogen, renewable natural gas and carbon capture technology provide carbon reduction options for gas-powered infrastructure being built beyond 2020, while also helping our customers meet their need for reliable and affordable power. This flexible, low-carbon generation is critical to meeting the objectives of reliability, affordability and sustainability, and allows for integration of additional renewable capacity.

Entergy and Invenergy Partnership to Focus on Utility-Scale Renewable Development

Entergy and Invenergy have agreed to co-develop renewable energy facilities in the Gulf South region. Invenergy brings renewable development expertise and access to a robust supply chain for equipment and installation services. Additionally, Invenergy has projects in the Entergy service territory with transmission interconnection rights. All of this will enable the two companies to collaborate to deliver projects at competitive costs and with earlier in-service dates.

Entergy and Energy Impact Partners

Through a shareholder-funded program, Entergy joined the EIP Platform to collaborate with innovators and gain insights. EIP manages $1.5 billion in global venture capital assets and supports the transition to a sustainable energy future by bringing together entrepreneurs and forward-looking energy and industrial companies.

Existing and Advanced Nuclear – We are continuing to invest in our existing zero-carbon nuclear fleet to extend and preserve those assets. Entergy has not made any definitive decisions or announcements regarding the potential for subsequent license renewals; however, we are considering this as a part of our future, long-term energy mix as shown in the illustrative scenario in this addendum. Additionally, we are monitoring advanced technologies, such as advanced nuclear fuels, as well as small modular fission and fusion reactors to determine what role they may play in our future resource mix.

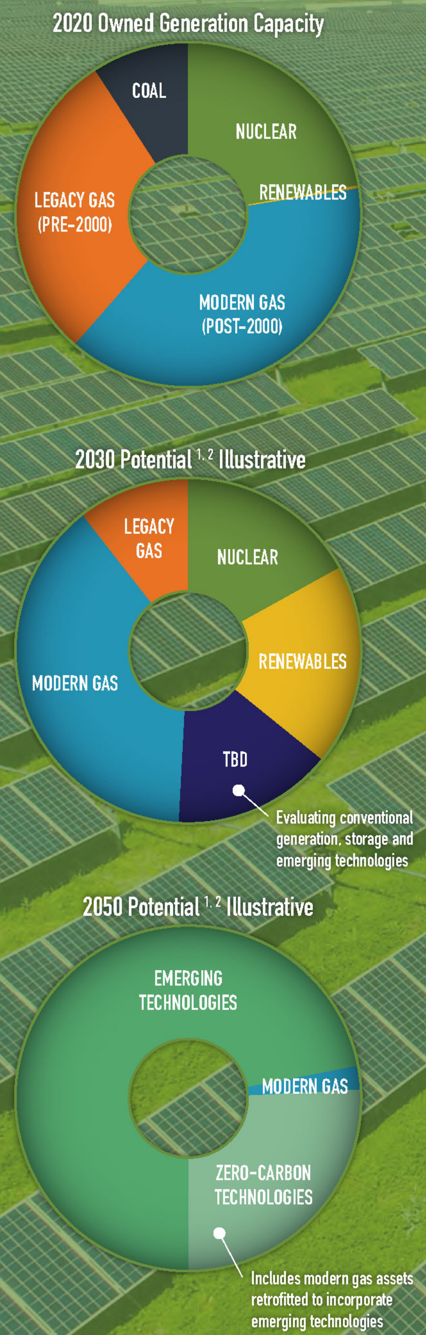
Renewables and Storage – We currently are investing in multiple solar generation facilities and expect to continue to expand our renewable energy capacity over the coming decades. As needed, battery storage will complement these clean generation assets. We expect investment in renewables plus storage to continue beyond 2030, eventually becoming a larger part of our resource mix. Entergy is also monitoring wind technology developments both on- and offshore; other renewable options and storage technologies that eventually may represent capacity; and resource investment opportunities.

Other Technologies – Entergy monitors developments not only in the technologies described in this report, but also in new technologies that may represent resource options over the next three decades. Advanced generation technologies and different low- to zero-carbon approaches to generating power likely will emerge and become commercially viable by 2050.

Uncertainties and Risk – The technologies and strategies discussed in this report are in various stages of development and deployment. Some of these are considered "state of the market," while others are "state of the art" and some are nascent. Those that are less developed or deployed present more investment risk today. Some of the technologies have a higher likelihood of reaching maturity than others. Due to our commitment to achieving net-zero carbon emissions by 2050, Entergy is monitoring these technologies as they develop and working to advance these technologies through joint endeavors with other industry partners, research organizations and industry groups. The points of view described above will continue to be refined as these developments occur, and when appropriate, these technologies will be proposed for inclusion in the company's resource plan.

Transition Equity – Entergy is committed to achieving our environmental sustainability goals and commitments while balancing the reliability of our system and affordability for our customers. Additionally, we believe that sustaining economic development and growth during our transition is essential to continuing to improve the quality of life for customers and communities in our region. Accordingly, as this transition occurs, Entergy considers human rights, social equity and environmental justice issues important to employees, the communities we serve and society as a whole. Entergy is committed to addressing employees impacted by the transition. Our robust corporate social responsibility efforts have focused on poverty elimination and workforce development for the last two decades. We seek not only to avoid disproportionate impacts of the investments necessary for this transition, but also to ensure the economic, health and environmental benefits of the transition are shared across the communities we serve.

Entergy's Capital Plan – Our five-year, $21 billion capital plan is consistent with and supportive of a transition to a low-carbon power generation fleet and our long-term commitment to achieving net-zero carbon emissions, while



also improving reliability, strengthening system resiliency and facilitating integration of low-carbon resources. The plan also accommodates our ability to create a platform for innovative products and services and provide customer solutions optimized by coupling digital technology with analytics. For the generation fleet, we are investing $9 billion over the next five years to continue transitioning our fleet to modern, efficient gas units, support our existing nuclear assets and integrate a significant amount of renewable energy generation. Utility-scale renewable generation and hydrogen infrastructure partnerships provide near-term experience with technologies necessary for meeting a net-zero commitment and represent potential future capital investment opportunities.

Entergy's 2050 Climate Scenario Analysis

The impact of our two decades of action on our portfolio transformation strategy is evident in the evolution of our resource mix since 2000 (our base year). The illustrative projection for 2030 remains generally consistent with the mix presented in our 2019 climate report. Below we present the results of an analysis that includes a comprehensive technology review and development of an analysis tool to evaluate integration of the various technology options described previously in this report. A significant amount of uncertainty exists with respect to the assumptions on which this scenario is based. Additionally, some of the modeling assumptions described below do not necessarily match retirement dates assumed in regulatory proceedings. The charts presented here represent an illustrative capacity and generation mix projection based on Entergy's current technology points of view.

Assumptions for the Illustrative Scenario

- *Existing coal* – This scenario assumes that all coal-powered capacity is retired by the end of 2030 – Entergy already has announced our intent to cease burning coal by the end of 2030;
- *Pre-2000 gas units* – It is assumed that all pre-2000 gas is retired no later than the 2040s – this would complete the turnover of the company's legacy fossil generation fleet, leaving only post-2000 modern, efficient gas;
- *2000 to 2019 gas units* – It is assumed that most of these units are retired by 2050; however, for some of these units, life extension beyond the current planning assumption of 30 years may be required to support the ongoing deployment of other low- to zero-carbon technologies, but it is assumed that this vintage of gas generation is fully retired by 2050;
- *Gas supply decarbonization* – Strategies such as co-firing of either renewable natural gas or hydrogen are deployed beginning in the mid- to late-2020s on modern, efficient gas units;
- *Carbon capture, utilization and sequestration* – This technology is assumed to be installed on post-2020 modern, efficient gas units beginning in the late-2030s;
- *Existing nuclear* – It is assumed that all nuclear units receive subsequent license renewal, extending the life of the fleet beyond 2050;
- *Advanced nuclear* – Entergy assumes that this technology becomes available in the 2040s, resulting in the deployment of 1 gigawatt of capacity by 2050; and,
- *Renewables and storage* – Deployment of renewable energy sources (some with storage) continues for the next three decades, ultimately resulting in over 10 gigawatts of capacity.

1- Subject to integrated resource planning processes, economic evaluations and regulatory approvals. **2**- Potential 2030 and Potential 2050 portfolios assume technology advancements and/or declining costs of carbon-free technologies in order to balance environmental stewardship with affordability and reliability; offsets utilized for remaining emissions.

While not specifying a supply plan, this scenario illustrates how Entergy's 2050 net-zero commitment could be achieved while meeting all energy and capacity requirements. This view is not a recommended supply plan and has not undergone an economic analysis; rather, it is an example of how Entergy could reach net-zero emissions if the technologies develop and a resulting generation portfolio is found to be cost-effective and reliable. Specific supply plans will be developed in coordination with our regulators and other stakeholders and will require regulatory approval consistent with our legal obligation to provide affordable and reliable energy.

This illustrative scenario will be adjusted over time as technology develops and evolves, limited by our ability to incorporate new technologies into our resource mix due to the long lead times inherent in the regulatory and resource planning processes. Entergy will continue to monitor technology developments that impact the potential use, cost, efficiency and emissions of these projections.

Entergy's Three-Phase Approach to Decarbonization

The chart below provides some additional context for the illustrative scenario presented in the previous section of this report. Entergy's decarbonization pathway began over the last two decades and now extends over the next three decades, meaning that our phased approach spans five decades.

2001-2020

One of the lowest CO_2 emission rates in the electric power sector

Since 2001, after voluntarily committing to stabilize and reduce our emissions, Entergy has reduced its carbon emissions by almost 25%.

Entergy maintains one of the lowest CO_2 emission rates in the industry with a combination of nuclear, renewable and natural gas-fired generation.

2020-2030

A plan to reduce our carbon intensity 50% by 2030

Over the coming decade, Entergy is committed to reducing its carbon emissions intensity by 50% below 2000 levels by 2030, while enabling carbon reductions throughout the economy (e.g., industry and transportation).

This generally is in line with scenarios aimed at limiting global temperature increases to well below 2°C.*

2030-2050

Committed to net-zero carbon emissions by 2050

Entergy is fully committed to achieving net-zero CO_2 emissions by 2050.

According to the Intergovernmental Panel on Climate Change (IPCC), to limit global warming to 1.5°C above pre-industrial levels and avoid the most catastrophic impacts of climate change, the world must reach net-zero CO_2 emissions by mid-century.

Technology advancements will be critical to making this step change in performance.

* Entergy's 2030 goal is to reduce its carbon intensity to approximately 532 pounds of CO_2 per megawatt hour (lb/MWh) of electricity production. The International Energy Agency's 2°C Scenario (2DS) projects a carbon intensity of 514 lb/MWh for the U.S. power sector in 2030, and the Beyond 2°C Scenario (B2DS) projects a carbon intensity of 510 lb/MWh in 2030.

Conclusion

Entergy's leadership in sustainability and environmental stewardship has been a hallmark of who we are for two decades. Entergy has one of the lowest carbon dioxide emission rates in the electric power sector and was the first U.S. utility to announce a voluntary carbon commitment. This leadership on climate action continues today with our near-term 2030 goal and long-term commitment to achieving net-zero carbon emissions by 2050. Entergy recognizes that technological advancements are critical to achieving these emission reductions and is establishing partnerships and collaborating across our full value chain on the necessary technology developments. Our capital plan is in line with a low-carbon transition, and our leadership is held accountable for results through Entergy's executive compensation program. Entergy is committed to continuing – and strengthening – its environmental stewardship; actively engaging in partnerships to develop long-term, sustainable climate solutions; realizing the opportunities that lie ahead of us in meeting our climate commitment; and driving toward results that benefit our customers, our communities, our society and our world.

Forward-Looking Statements Disclaimer

In this report, and from time to time, Entergy Corporation makes certain "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, among other things, statements regarding Entergy's operational outlooks and capital plan; statements regarding its environmental plans, goals, beliefs and expectations, including statements regarding its greenhouse gas reduction goals and strategies and statements regarding the planned addition of renewable generation, potential technological advances, legacy asset retirements, nuclear license extensions, offsets and other potential means of achieving its environmental goals; statements regarding opportunities to partner with customers and others to advance technology development or reduce societal emissions; and other statements of Entergy's plans, beliefs, or expectations included in this presentation.

Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. Except to the extent required by the federal securities laws, Entergy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise. Forward-looking statements are subject to a number of risks, uncertainties, and other factors that could cause actual results to differ materially from those expressed or implied in such forward-looking statements, including (a) those factors discussed elsewhere in this presentation and in Entergy's most recent Annual Report on Form 10-K, any subsequent Quarterly Reports on Form 10-Q, and Entergy's other reports and filings made under the Securities Exchange Act of 1934; (b) uncertainties associated with (1) rate proceedings, formula rate plans, and other cost recovery mechanisms, including the risk that costs may not be recoverable to the extent anticipated by the utilities and (2) implementation of the ratemaking effects of changes in law; (c) uncertainties associated with efforts to remediate the effects of major storms and recover related restoration costs; (d) risks associated with operating nuclear facilities, including plant relicensing, operating, and regulatory costs and risks; (e) changes in decommissioning trust fund values or earnings or in the timing or cost of decommissioning Entergy's nuclear plant sites; (f) legislative and regulatory actions and risks and uncertainties associated with claims or litigation by or against Entergy and its subsidiaries; (g) risks and uncertainties associated with execution on our business strategies, including strategic transactions that Entergy or its subsidiaries may undertake and the risk that any such transaction may not be completed as and when expected and the risk that the anticipated benefits of the transaction may not be realized; (h) effects of changes in federal, state, or local laws and regulations and other governmental actions or policies, including changes in monetary, fiscal, tax, environmental, or energy policies; (i) the effects of changes in commodity markets, capital markets, or economic conditions; (j) impacts from a terrorist attack, cybersecurity threats, data security breaches, or other attempts to disrupt Entergy's business or operations, and/or other catastrophic events; (k) the direct and indirect impacts of the COVID-19 pandemic on Entergy and its customers; and (l) the effects of technological change, including the costs, pace of development and commercialization of new and emerging technologies.

the resource serve to reduce customers' costs.

B. Affiliate PPAs

Q15. DID ETI INCUR ANY CAPACITY COSTS DURING THE TEST YEAR AS A RESULT OF A PPA WITH AN AFFILIATE?

A. Yes. ETI is party to life-of-unit PPAs for two generation facilities owned by ELL: the River Bend nuclear plant and the natural gas-fired Perryville plant. ETI makes monthly payments to ELL for its share of capacity (29.75% of River Bend and 31.88% of Perryville) and associated energy pursuant to a cost-based formula rate.

Since their inception in January 2008, ETI's payments associated with the River Bend and Perryville PPAs were made pursuant to Service Schedule MSS-4 of the Entergy System Agreement. With the termination of the Entergy System Agreement on August 31, 2016, a Federal Energy Regulatory Commission ("FERC")-approved replacement rate schedule was implemented to replicate the cost-based formula rate found in Service Schedule MSS-4.[4] That replacement tariff is currently utilized for ETI's payments associated with the River Bend and Perryville PPAs. The energy costs associated with these PPAs are treated as eligible fuel expense recovered through ETI's Fixed Fuel Factor rate. The capacity costs are treated as non-fuel costs.

[4] FERC approved the replacement tariff in Entergy Services, Inc. Docket Nos. ER13-1508, et al. Under this tariff, the cost structure for the underlying resource is unique to the respective plant, but the formula rate charged is the same as is used for other transactions governing the purchase and sale of capacity and energy between Entergy Operating Companies.

III. DEACTIVATION DATE ASSUMPTIONS

Q16. WHAT ARE THE DEACTIVATION DATE ASSUMPTIONS SUPPORTING THE USEFUL LIVES USED IN THE DEPRECIATION STUDY?

A. See highly sensitive Exhibit ARM-2 for the deactivation date assumptions for ETI's owned generating units, which support the useful lives used in the depreciation study for this base rate case proceeding. These deactivation date assumptions are used in ETI's long-term resource planning process and were approved by the ETI Operating Committee as a part of the Business Plan 2022 ("BP22") planning process. They represent a reasonable expectation of the useful lives of these resources. Deactivation assumptions are necessary reference points used to assess current and future capacity needs, and to appropriately budget and prioritize maintenance dollars among ETI's fleet of resources.

Q17. WHAT ARE THE DEACTIVATION DATE ASSUMPTIONS FOR THE NEW GENERATING UNITS INCLUDED IN THIS BASE RATE CASE?

A. There are several resources included in this base rate case filing that were not included in the depreciation study included in Docket No. 48371. These include the Hardin Facility, MCPS, and two utility-owned backup generators at H-E-B stores across ETI's service territory. The useful life used in the depreciation study for the Hardin Facility is 2041, which reflects the date agreed to in the approved Settlement Agreement in Docket No. 50790.[5] In 2041, the Hardin Facility will be

[5] Docket No. 50790, Order at Finding of Fact Nos. 50-51 and Ordering Paragraph No. 4.

40 years old. The deactivation date for MCPS is based on the [redacted]-year useful life for new combined cycle gas turbines. Finally, the Company assigned a [redacted]-year useful life for the backup generators based on the manufactures' stated design life for these resources.

Q18. PLEASE DESCRIBE HOW UNIT DEACTIVATION ASSUMPTIONS ARE DEVELOPED FOR USE IN RESOURCE PLANNING.

A. As part of the annual supply planning process, ETI along with ESL's Enterprise Planning Group ("EPG") and Power Generation organization monitor a host of factors, including market and unit conditions, to determine reasonable deactivation dates for ETI's generation fleet. Power Generation monitors, ascertains the condition of, and budgets for the Entergy Operating Companies' existing generation fleet. Power Generation has a number of processes in place to assess unit conditions, on both an immediate and long-term basis. In addition, Power Generation occasionally engages third-party consultants to assist with unit condition assessments. Power Generation evaluates continued investments as resources near the end of their useful lives, as there is a higher risk of major component or unit failure and lower certainty that the benefits obtained with sustaining unit availability will outweigh the costs of those investments.

Based on these ongoing assessments, deactivation assumptions for ETI's generation fleet are developed based on a number of factors, including unit age, criticality, reliability, expected useful life, estimates of the cost to maintain each unit, cost of compliance with environmental regulations, and evaluation of current

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Fourth Set of Data Requests	Prepared By: Antonette Harvey Sponsoring Witnesses: Beverly Gale, Anastasia R. Meyer
of Requesting Party: Texas Industrial Energy Consumers	Beginning Sequence No. LC2621 Ending Sequence No. LC2621

Question No.: TIEC 4-4 Part No.: Addendum:

Question:

Have the co-owners of Nelson 6 or Big Cajun II Unit 3 determined when either of those plants will be decommissioned? If so, please state when those plants will be decommissioned and provide any analyses supporting those decommission dates.

Response:

No.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Fourth Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Anastasia R. Meyer Sponsoring Witness: Anastasia R. Meyer Beginning Sequence No. LC2624 Ending Sequence No. LC2624

Question No.: TIEC 4-8 Part No.: Addendum:

Question:

Please state when ETI believes Nelson 6 and Big Cajun II Unit 3 should be retired and explain the bases for ETI's belief.

Response:

There are currently no scheduled retirement dates for Entergy Texas, Inc. ("ETI") owned generating units. The deactivation assumptions included in the Direct Testimony of Anastasia R. Meyer represent ETI's reasonable expectation based on currently available information. Please see Anastasia R. Meyer's Direct Testimony, Q20 through Q31, and Exhibits ARM-3 through ARM-5 for planned deactivation dates and rationale.

generates 554.5 MW[12] and is jointly owned by Louisiana Generation, LLC (58%), ELL (24.15%), and ETI (17.85%). It is operated by Cleco Cajun LLC. Unit 3 went into service in 1983 and is currently 39 years old. As a minority owner, ETI has limited control over the ongoing operations and retirement of Unit 3.

Q26. HAS CLECO PUBLICLY COMMITTED TO DEACTIVATING BIG CAJUN 2 UNIT 3?

A. Yes. In response to a March 18, 2020 Regional Haze Four-Factor Analysis Information Collection from the Louisiana Department of Environmental Quality, Trinity Consultants prepared and submitted a report on behalf of Cleco Power, Cleco Cajun LLC, and Louisiana Generating, LLC (together, "Cleco").[13] In that report, dated July 24, 2020, Cleco committed to "retir[ing] Units 2 and 3 no later than December 31, 2032."[14]

Q27. COULD CLECO DEACTIVATE BIG CAJUN 2 UNIT 3 SOONER THAN 2032?

A. Yes. The report provides the estimated costs of implementing SO_2 and NO_x emission reduction technologies and the timing of such implementation. It estimates $94.8 million in annual costs for Big Cajun 2 Unit 3 for SO_2 and NO_x

---

12 Unit capacity based on Generation Verification Test Capacity for MISO Planning Year 2022-2023 (June 1, 2022 through May 31, 2023).

13 Response to March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request, July 24, 2020, available at https://edms.deq.louisiana.gov/app/doc/view?doc=12280837.

14 *Id.* at 1-1.

emission reductions beginning in 2028, when there is only four years left of the unit's remaining useful life.[15] The tables below are reproduced from the report:

Table 2-4. Estimated Costs of SO_2 Emissions Reduction Options

Unit	SO_2 Reduction Option	Total Capital Cost ($MM)	Annualized Capital Costs ($MM/year)	Annual O&M Costs ($MM/year)	Total Annual Costs ($MM/year)	Cost Effectiveness ($/ton)
3	WFGD	335.5	99.1	26.2	125.3	16,209
	DFGD	263.7	77.9	25.3	103.2	13,809
	DSI	25.5	7.5	14.2	21.7	5,250

Table 3-4. Estimated Costs of NO_x Emissions Reduction Options

Unit	NO_x Reduction Option	Total Capital Cost ($MM)	Annualized Capital Costs ($MM/year)	Annual O&M Costs ($MM/year)	Total Annual Costs ($MM/year)	Cost Effectiveness ($/ton)
1 (nat. gas only)	SCR	48.2	4.6	3.7	8.2	22,482
2	SCR	53.4	15.8	3.8	19.6	47,568
3	SCR	204.6	60.4	12.7	73.1	68,986

Cleco could decide to deactivate Big Cajun 2 Unit 3 before 2028 to avoid these substantial additional costs. For instance, Cleco and SWEPCO agreed to shut down their Dolet Hills plant at the end of 2021 in an effort to reduce costs,[16] five years earlier than the 2026 date SWEPCO committed to as part of a settlement in a contested proceeding before the Arkansas Public Service Commission.[17]

As a regulated utility, ETI must engage in resource planning to ensure it

---

[15] *See id.* at 2-3, 3-3 (Tables 2-4 and 3-4).

[16] *See id.* at 1-2 ("Cleco will be ceasing operations at Dolet Hills by the end of 2021."); Elena Vasilyeva *Cleco, SWEPCO to close Louisiana Coal Plant Early*, Argus Media, Nov. 1, 2021, available at https://www.argusmedia.com/en/news/2269477-cleco-swepco-to-close-louisiana-coal-plant-early.

[17] *In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs*, Arkansas Public Service Commission Docket No. 19-008-U, Unanimous Settlement Agreement at 11 (Oct. 15, 2019); *see* Docket No. 19-008-U, Notice Pursuant to Unanimous Modified Settlement Agreement (Nov. 25, 2020) ("This Notice is intended to notify the parties herein that the decision has been made by SWEPCO and Cleco management to retire the Dolet Hills Power Station after completion of the seasonal operation period of 2021, but no later than December 31, 2021, rather than December 31, 2026.").

PUC DOCKET NO. 51415
SOAH DOCKET NO. 473-21-0538

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

This Order addresses the application of Southwestern Electric Power Company (SWEPCO) for authority to change its rates. Through its application and rebuttal testimony, SWEPCO sought a Texas retail revenue requirement of $451,529,538.

A hearing on the merits was held between May 19 and May 26, 2021 at the State Office of Administrative Hearings (SOAH). On August 27, 2021, the SOAH administrative law judges (ALJs) filed their proposal for decision in which they recommended a Texas retail revenue requirement decrease to SWEPCO's Texas retail revenue requirement of $26,495,690. In response to the parties' exceptions and replies to the proposal for decision, on November 9, 2021, the SOAH ALJs filed a letter making changes to the proposal for decision.

The Commission adopts the proposal for decision as modified by the ALJs, including findings of fact and conclusions of law, to the extent provided in this Order.

I. Discussion

The Commission's decisions result in a Texas retail base-rate revenue requirement of $400,742,913, which is a decrease of $50,786,625 from SWEPCO's requested Commission-authorized revenue requirement. New findings of fact 24A-I and 315A-C are added to address the procedural history of this docket after the close of the evidentiary record at SOAH. Additionally, the Commission modifies finding of fact 286 to reflect the rate schedules produced by Commission Staff's updated number run.

A. Self-Insurance Reserve and Hurricane Laura Costs

The Commission disagrees with the SOAH ALJs' finding that SWEPCO failed to sufficiently quantify the amount of savings of the self-insurance in comparison to commercial insurance to support establishment of a self-insurance reserve. In this proceeding SWEPCO presented adequate testimony on cost savings attributable to the self-insurance plan. While

705

41. In Docket No. 46449, the Commission determined that: (1) because Welsh Unit 2 was retired and no longer generating electricity, it was not used by and useful to SWEPCO in providing electric service to the public; (2) because Welsh Unit 2 was no longer used and useful, SWEPCO could not include its investments associated with the plant in its rate base and earn a return on that remaining investment; (3) allowing SWEPCO a return of, but not on, its remaining investment in Welsh Unit 2 properly balances the interests of customers and shareholders with respect to a plant that no longer provides service; and (4) the appropriate accounting treatment that results in the appropriate ratemaking treatment was to record the undepreciated balance of Welsh Unit 2 in a regulatory-asset account rather than leaving it in accumulated depreciation.

42. Consistent with the Commission's rate treatment of the retired Welsh Unit 2 in Docket No. 46449, the net book values of the retired Lieberman Unit 2, Lone Star Unit 1, and Knox Lee Units 2, 3, and 4 should be removed from rate base, to cease earning a return and be placed in a regulatory asset.

43. The regulatory asset should be amortized over the four-year period in which the rates approved in this case are expected to be in effect.

Dolet Hills

44. Dolet Hills is a lignite-fueled generating unit located southeast of Mansfield, Louisiana, and jointly owned by SWEPCO; Cleco Power, LLC; Northeast Texas Electric Cooperative, Inc.; and Oklahoma Municipal Power Authority. CLECO is the majority owner and operator of Dolet Hills.

45. Dolet Hills went into commercial operation in 1986, and its previously established useful life extends until 2046.

46. Dolet Hills is fueled by lignite mined in the same area by Dolet Hills Lignite Company (DHLC), a SWEPCO subsidiary. An equity return on DHLC and associated taxes is currently included in SWEPCO's rate base.

47. An investment in the Oxbow Mine reserves is also included in SWEPCO's rate base.

48. In early 2020, SWEPCO and CLECO determined that all economically recoverable lignite at the Dolet Hills associated mines had been depleted, that mining operations should cease, and that Dolet Hills should be retired by the end of 2021.

49. In deciding whether to retire Dolet Hills, SWEPCO evaluated mining operations and the costs of operating the plant beyond 2021. SWEPCO studied the expected total SWEPCO system cost to serve customers, comparing the scenario where Dolet Hills continues to serve customers through 2046 versus through a December 31, 2021 retirement. The study determined that the expected least-cost path for SWEPCO and its customers lay in retiring the plant.

50. No party contested the prudence of SWEPCO's decision to retire Dolet Hills at the end of 2021. The decision was prudent.

51. Dolet Hills will be retired on December 31, 2021 and will continue providing service until that time. SWEPCO plans to continue operating the plant on a seasonal basis, principally during the peak summer months, as it has done in recent years. However, the plant remains available in case called upon by SWEPCO or CLECO's respective regional transmission organizations for reliability reasons.

52. Until its retirement, output from Dolet Hills will continue to be offered into the energy market year-round, incurring expenses required to ensure the unit is available to operate when called upon.

53. Although mining operations ceased in May 2020, SWEPCO's investment in the Oxbow reserves will continue to provide service until Dolet Hills' retirement, as the plant will continue to burn previously mined lignite to generate electricity.

54. Similarly, DHLC will continue to exist and deliver lignite to Dolet Hills, and SWEPCO will continue incurring this non-eligible fuel expense through the plant's retirement.

55. In this case, the rate year began on the relate-back date, March 18, 2021.

56. Dolet Hills, SWEPCO's Oxbow investment, and DHLC have provided service to customers during the rate year.

57. Good cause exists to make post-test-year reductions to SWEPCO's rate base to reflect, consistent with the Commission's rate treatment of Welsh Unit 2 in Docket No. 46449, that Dolet Hills, the Oxbow investment, and DHLC will cease to provide service to SWEPCO's customers when the plant retires on December 31, 2021.

58. It is appropriate to remove all cost recovery for Dolet Hills, the Oxbow investment, and DHLC from base rates and address these issues instead in a Dolet Hills rate rider.

59. Through the Dolet Hills rate rider, SWEPCO should be permitted, with respect to the period between March 18, 2021 (the date when the rates are effective) and December 31, 2021 (the date of Dolet Hills' retirement) (the operative-plant phase of the Dolet Hills rate rider), to recover the costs ordinarily permitted for an operating generating plant, including a return on the plant's net book value (including applicable accumulated deferred federal income taxes and unused materials and supplies), depreciation, and O&M. SWEPCO should similarly be permitted to continue earning a return on the Oxbow investment and the return on equity and associated taxes for DHLC. The charges in the Dolet Hills Rate Rider should be subject to true-up to reflect an updated-net-book value of Dolet Hills after its retirement and again after the plant is closed and final demolition costs are known.

60. With respect to the period after December 31, 2021 (the post-retirement phase of the Dolet Hills rate rider), the remaining net book values of Dolet Hills should be placed in a regulatory asset to be amortized without a return. All other cost recovery for Dolet Hills, the Oxbow investment, or DHLC under the Dolet Hills rate rider should cease, as the assets will no longer be providing service.

61. SWEPCO's recovery of Dolet Hills' remaining net book value (whether through depreciation during the operative-plant phase or recovery from the regulatory asset during the post-retirement phase) should be amortized in accordance with the asset's useful life ending in 2046.

62. DELETED.

63. Amortizing these assets in accordance with Dolet Hills' useful life ending in 2046 equitably balances the interests of SWEPCO and both its current and future customers.

64. It would be inequitable to SWEPCO's current customers to accelerate SWEPCO's recovery of these assets, as SWEPCO proposes to do, through offsetting the excess accumulated deferred federal income taxes (ADFIT) SWEPCO owes to its current customers and amortizing the balance over only four years.

65. SWEPCO's calculation and use of estimated demolition costs for Dolet Hills is reasonable.

Coal and Lignite Inventories

66. SWEPCO must maintain solid fuel inventories to assure a continuous supply of coal and lignite of appropriate quality, delivered at a reasonable cost over a period of years to promote the generation of the lowest cost per kilowatt-hour (kWh) of electricity, within the constraints of safety, reliability of supply, unit design, and environmental requirements.

67. Coal and lignite deliveries must be arranged so that sufficient fuel is available at all times to provide and maintain adequate and dependable electric service for SWEPCO's customers.

68. Setting inventory levels for SWEPCO's coal power plants (Welsh, Flint Creek, and Turk) and lignite power plants (Pirkey and Dolet Hills) based on the average level of burn from the test year would negatively impact SWEPCO's ability to reliably serve the needs of its customers and SPP and expose SWEPCO's customers to reliability risk.

69. Setting coal and lignite inventory targets for SWEPCO's coal and lignite power plants based on full-load burn ensures that adequate inventory is available to provide the necessary reliability for SWEPCO customers and SPP.

70. The target coal and lignite inventory levels SWEPCO requests to include in rate base are reasonable and necessary to ensure adequately reliable service to its customers.

71. However, because Dolet Hills will be retired on December 31, 2021, and consistent with the findings regarding the appropriate rate treatment of SWEPCO's investments in that plant, the Oxbow reserves, and DHLC, SWEPCO's lignite inventory for Dolet Hills should be removed from rate base and placed in the Dolet Hills Rate Rider; SWEPCO should recover a return on that inventory only during the operative-plant phase, and have no cost recovery for the inventory during the post-retirement phase.

72. Good cause exists to make these post-test year adjustments regarding SWEPCO's lignite inventory for Dolet Hills.

48. In early 2020, SWEPCO and CLECO determined that all economically recoverable lignite at the Dolet Hills associated mines had been depleted, that mining operations should cease, and that Dolet Hills should be retired by the end of 2021.

49. In deciding whether to retire Dolet Hills, SWEPCO evaluated mining operations and the costs of operating the plant beyond 2021. SWEPCO studied the expected total SWEPCO system cost to serve customers, comparing the scenario where Dolet Hills continues to serve customers through 2046 versus through a December 31, 2021 retirement. The study determined that the expected least-cost path for SWEPCO and its customers lay in retiring the plant.

50. No party contested the prudence of SWEPCO's decision to retire Dolet Hills at the end of 2021. The decision was prudent.

51. Dolet Hills will be retired on December 31, 2021 and will continue providing service until that time. SWEPCO plans to continue operating the plant on a seasonal basis, principally during the peak summer months, as it has done in recent years. However, the plant remains available in case called upon by SWEPCO or CLECO's respective regional transmission organizations for reliability reasons.

52. Until its retirement, output from Dolet Hills will continue to be offered into the energy market year-round, incurring expenses required to ensure the unit is available to operate when called upon.

53. Although mining operations ceased in May 2020, SWEPCO's investment in the Oxbow reserves will continue to provide service until Dolet Hills' retirement, as the plant will continue to burn previously mined lignite to generate electricity.

54. Similarly, DHLC will continue to exist and deliver lignite to Dolet Hills, and SWEPCO will continue incurring this non-eligible fuel expense through the plant's retirement.

55. In this case, the rate year began on the relate-back date, March 18, 2021.

56. Dolet Hills, SWEPCO's Oxbow investment, and DHLC have provided service to customers during the rate year.

The other parties took umbrage with Mr. Hevert's contentions regarding environmental compliance. Perhaps the most telling was Staff, who said:

> Of course, Mr. Hevert ignores the fact these risks [related to environmental compliance] run throughout the electric utility industry. Any electric utility with a similar proportion of coal generation, or any coal generation, will incur increased environmental compliance costs. SWEPCO is no different. This is simply not a reason to inflate SWEPCO's ROE artificially.[468]

Staff is correct. SWEPCO is no different than other utilities with coal-fired generation as a part of their portfolio of resources. The cost of environmental compliance is a fact of life in the utility industry and is not isolated to SWEPCO alone.

The first question that must be addressed is the appropriate proxy group. There were essentially only three competing views on this issue–one presented by Mr. Hevert (and adopted by Messrs. Parcell and Gorman, with one exception in the latter case), one presented by Dr. Szerszen and Mr. Hill, and one presented by Mr. Cutter. First, with respect to the divergence between Mr. Gorman and Mr. Hevert, the ALJs believe that Mr. Hevert is correct in including Empire in the proxy group. Although Empire suspended its dividend, it is currently paying a dividend and has demonstrated to the ALJs that it will continue to do so. It is, therefore, comparable to SWEPCO. The ALJs acknowledge that Dr. Szerszen's 23-member proxy group is larger than that proposed by Mr. Hevert and could provide a more robust sample, but the fact that Mr. Hevert's group is smaller does not necessarily disqualify it from consideration. The ALJs agree with Mr. Hevert that Dr. Szerszen's and Mr. Hill's groups sacrifice comparability for size. Both included two companies with negative projected five-year analysts' growth rates. Ameren's problems, which caused it to abandon an entire segment of its business, make its choice as a proxy company unreasonable, and Entergy's ongoing business transformation, combined with negative earnings, is not emblematic of normal ongoing business operations. Finally, Mr. Cutter's proxy group was selected through the use of a screening process that deviates too much from the accepted norm. It rejected a criterion (no recent mergers/capital expansions) that Mr. Cutter had consistently used as recently as 2012 to increase the size of his

[468] Staff Reply Brief at 16.

depreciation expense of $1.114 million and a reduction to the Company's proposed revenue requirement of $1.152 million.[608]

For the same reasons advocated by Cities, CARD rejects SWEPCO's proposal to reduce the life span of the Dolet Hills Plant from 60 years to 40 years. Like Cities, CARD argues that SWEPCO failed to show that Dolet Hills would have no remaining reserves after 2026, nor does SWEPCO provide any analysis of whether alternative fuel sources are available to supplement the lignite from Oxbow Mine.

ALJs' Analysis

The ALJs do not find that SWEPCO has supported its proposal to reduce the life span of the Dolet Hills Plant from 60 years to 40 years. SWEPCO offers a single argument to support its request—that the Dolet Hills plant must match the availability of its specific fuel source. The availability of the fuel from the one source should not determine a plant's service life because it is very likely that SWEPCO can obtain fuel from other sources. When SWEPCO recently purchased the Oxbow mine, for example, the fuel resources were extended under the contract for the Dolet Hills plant to at least 2026.[609] It is important in determining the service life of the Dolet Hills Plant to note SWEPCO's Pirkey Plant, which closely resembles the Dolet Hills Plant, has a 60-year service life.

Additionally, the ALJs agree with Cities that the settlement approved by the LPSC is not binding in this case. Furthermore, that settlement did not determine the service life for the unit; it required only that SWEPCO and CLECO extend the service life through 2026 at a minimum for depreciation purposes. The language suggests a minimum service life, not the maximum service life.

[608] Cities Ex. 3 (Kollen Direct) at 53 and Schedule LK-9.

[609] Cities Ex. 3 (Kollen Direct) at 50.

In SWEPCO's last Texas base rate case, filed August 28, 2009, SWEPCO proposed a 60-year service life. That proceeding recommended a 60-year life span for the Dolet Hills Plant.[610] Other than the fuel source argument, SWEPCO has not shown a justifiable reason to shorten the useful life of the Dolet Hills Plant to 40 years in this proceeding. Therefore, the ALJs recommend that the Dolet Hills Plant's current expected service life of 60 years remain. This results in a reduction in depreciation expense of $1.114 million and a reduction to the Company's proposed revenue requirement of $1.152 million.[611]

d. Welsh Unit 2 Life

As discussed previously, as part of its settlement on the Turk Plant, SWEPCO agreed to retire Welsh Unit 2 in 2016. Accordingly, SWEPCO performed depreciation studies with a useful life for Welsh Unit 2 ending 2016.

Cities and CARD reject SWEPCO's proposal to retire Welsh Unit 2 in 2016. Cities and CARD advocate that Welsh Unit 2's original useful life of 60 years be maintained. They propose that if the unit is ultimately retired, SWEPCO can request rate treatment to accommodate that retirement in a future rate case. Meanwhile, they contend that the Commission in this case should continue to assume that the useful life of Welsh 2 for ratemaking purposes is consistent with that of Welsh Units 1 and 3. Assuming that 2040 is reasonable retirement for Welsh 2, the effect of Cities' and CARD's recommendation is a reduction to depreciation expense of $1.042 million and a reduction in revenue requirement of $1.079 million.[612]

610 Cities Ex. 3 (Kollen Direct) at 50.

611 Cities Ex. 3 (Kollen Direct) at 53 and Schedule LK-9.

612 Cities Ex. 3, (Kollen Direct) at 45-46 and Schedule LK-8.

ALJs' Analysis

The ALJs recommend a disallowance for the Turk Plant. However, regardless of whether the Commission accepts the ALJs' recommendation, the retirement date for Welsh Unit 2 should remain at 2040 (the original useful life of 60 years). As part of its settlement on the Turk Plant, SWEPCO agreed to retire Welsh Unit 2 in 2016. The issue of whether to retire Welsh Unit 2 was not fully addressed in this proceeding. The ALJs agree with the intervenors that a separate proceeding should be initiated to consider the retirement of Welsh Unit 2 along with SWEPCO's plans to replace the capacity from Welsh Unit 2. Accordingly, SWEPCO's proposal to accelerate recovery of the remaining undepreciated plant costs as part of this proceeding should be rejected. Because Welsh Unit 2 remains operational (although at a reduced capacity), and until the Commission has had an opportunity to evaluate the retirement of Welsh Unit 2, the ALJs recommend that the retirement date for Welsh Unit 2 be 2040. If SWEPCO eventually retires Welsh Unit 2 in 2016, it can request that retirement date in a future rate proceeding. A 2040 retirement date results in a reduction to depreciation expense of $1.042 million and a reduction in revenue requirement of $1.079 million.[613]

e. Production Plant Net Salvage

SWEPCO requested an overall production plant net salvage rate of negative 3.4%. The contested issues related to production plant net salvage include: (i) the plant demolition studies conducted for SWEPCO's power plants; (ii) the escalation of production plant removal costs to the expected retirement date; and (iii) the inclusion of interim retirements and net salvage on interim retirements in the production net salvage calculation.

i. SWEPCO Plant Demolition Studies

Rather than using a generic production plant net salvage rate or one that historically has been used, SWEPCO calculated its production plant net salvage using engineering studies of the

[613] Cities Ex. 3, (Kollen Direct) at 45-46 and Schedule LK-8.

cost to demolish and remove each of its power plants. These calculations took into account the specific attributes of each plant and were performed by Sargent & Lundy, LLC (S&L), a recognized power plant engineering firm.[614] SWEPCO witness David A. Davis testified that many utilities over the past 10 to 15 years have begun using demolition studies based on data specific for their power plants, instead of relying on generic net salvage values or historically used ratios.[615] Demolition studies take into account the specific, unique characteristics of the depreciable power plant. Mr. Davis asserted that this approach is better than using historical ratios or generic net salvage values.[616] The methodologies and approaches used by S&L in conducting the plant demolition studies were sponsored by SWEPCO witness Steven R. Bertheau, Senior Vice President and Project Director with S&L.[617] The overall net salvage rate of negative 3.4% requested by SWEPCO is inclusive of: (i) the removal costs and salvage in the S&L studies; (ii) the escalation of the S&L removal costs and salvage for each plant to the expected retirement date of the plant; and (iii) net salvage on interim retirements. Mr. Davis testified that SWEPCO's net salvage rate of negative 3.4% is reasonable compared to the Intervenors who simply made recommendations without any quantifiable connection between the objections they raised and their overall net salvage recommendations.[618]

Cities' Position

Cities claim that the Commission should exclude SWEPCO's proposed dismantling costs included in its requested depreciation rates.[619] The Company's estimated dismantlement costs are based on an assumed *total* dismantlement plus a 15% contingency.[620] However, Mr. Kollen testified that SWEPCO never fully dismantles its plants, rather, it sporadically conducts partial

614 SWEPCO Ex. 43 (Davis Direct) at 11-12, Exhibit DAD-1 at 10; SWEPCO Ex. 44 (Bertheau Direct) at 5-11, Exhibit SRB-1; SWEPCO Ex. 81 (Davis Rebuttal) at 17-24; SWEPCO Ex. 82 (Bertheau Rebuttal) at 4-8, Exhibit SRB-1R.

615 SWEPCO Ex. 81 (Davis Rebuttal) at 20.

616 SWEPCO Ex. 81 (Davis Rebuttal) at 18-19.

617 SWEPCO Ex. 44 (Bertheau Direct) at 6-8; SWEPCO Ex. 82 (Bertheau Rebuttal) at 6-7, 10-33, Exhibit SRB-1R.

618 SWEPCO Ex. 81 (Davis Rebuttal) at 21-23.

619 Cities Ex. 3 (Kollen Direct) at 58, 61.

620 Cities Ex. 3 (Kollen Direct) at 59.

PUC DOCKET NO. 40443
SOAH DOCKET NO. 473-12-7519

APPLICATION OF SOUTHWESTERN	§	**PUBLIC UTILITY COMMISSION**
ELECTRIC POWER COMPANY FOR	§	
AUTHORITY TO CHANGE RATES	§	**OF TEXAS**
AND RECONCILE FUEL COSTS	§	

ORDER ON REHEARING

This Order addresses the application filed on July 27, 2012 by Southwestern Electric Power Company (SWEPCO) for authority to change its rates and reconcile its fuel costs. The primary contested issue regarding the proposed increase involves the portion of SWEPCO's share of the costs of the Turk coal plant in Hempstead, Arkansas that are allocated to Texas.

SWEPCO's application sought a total-company revenue requirement of $1.033 billion, exclusive of fuel revenues. The requested Texas retail revenue requirement exclusive of fuel revenues was $329 million, which reflected an increase in annual Texas retail revenues of $83.37 million over its adjusted test-year revenues.[1] The increase primarily consists of the inclusion of the newly constructed Turk coal plant and Stall gas plant. For the fuel reconciliation period from April 1, 2009 through December 31, 2011, SWEPCO sought to reconcile a cumulative fuel under-recovery balance of $3,936,492, including interest, and proposed no surcharge. SWEPCO's reconciliation included proposed revisions to Dolet Hills Lignite Company benchmark price.

The State Office of Administrative Hearings' administrative law judges (ALJs) issued a proposal for decision on May 20, 2013. The ALJs' recommended approval of the application, with certain adjustments. Regarding the Turk plant, the ALJs recommended the disallowance of all Turk costs over approximately $934 million as being imprudently incurred in continuing construction after June 2010. The ALJs further recommended that approximately $260 million be allowed for the estimated costs to retrofit the Welsh Unit 2 coal plant that SWEPCO should have undertaken instead of completing the Turk plant. However, the ALJs recommended in the

[1] Rebuttal Testimony of Jennifer L. Jackson, SWEPCO Ex. 88, JLJ-1R at 2.

187. SWEPCO properly accounted for the effects of short-term debt, which the credit line fees support, through its calculation of AFUDC. The inclusion of short-term debt in the AFUDC calculation lowers both SWEPCO's return on assets and its depreciation expense, to the benefit of SWEPCO customers.

Obsolete Inventory

188. The Commission's rate filing package for generating utilities recognizes that obsolete inventory is an expense of doing business.

189. SWEPCO expensed $1.042 million (total Company) in obsolete inventory during the test year.

190. SWEPCO's level of obsolete inventory expense write-off during the test year is substantially greater than that of the past four years.

191. SWEPCO's requested $1.042 million in obsolete inventory expense is not reasonable and unlikely to be recurring and should be denied.

192. It is reasonable to set SWEPCO's level of obsolete inventory expense using a five-year average, which results in a reduction in the obsolete inventory expense of $0.105 million on a Texas retail basis, or a reduction of $0.108 million to SWEPCO's revenue requirement.

Production Plant Net Salvage

193. The plant demolition studies SWEPCO used to develop terminal removal cost and salvage for each of SWEPCO's generating facilities are reasonable. These studies were prepared by an experienced consulting engineering firm and incorporate reasonable methodology, data, assumptions, and engineering judgment.

194. It is reasonable for SWEPCO to escalate the terminal removal cost and salvage in the demolition studies (which are stated in first quarter 2012 dollars) to the expected final retirement date of each plant using a 2.5% inflation rate from the "Livingston Survey" dated December 2011 published by the research department of the Federal Reserve Bank of Philadelphia.

195. The rate at which interim retirements will be made is not known and measurable. Incorporation of interim retirements would best be done when those retirements are actually made. It is not reasonable to incorporate interim retirements, resulting in a reduction in the depreciation expense of $1 million on a Texas retail basis.

196. A 55-year estimated life span for the Turk plant is reasonable and results in a $9.1 million decrease in annual depreciation expense on a total Company basis for plant as of December 31, 2011, and a corresponding $3.0 million decrease in depreciation expense on a Texas jurisdictional basis.

197. Increasing the Stall plant's life span from 35 years to 40 years is reasonable. The 40-year life span results in a $1.7 million reduction in annual depreciation expense on a total Company basis for plant in service as of December 31, 2011, and a corresponding reduction in Texas retail depreciation expense of $550,000.

198. A 60-year estimated life span for the Dolet Hills plant is reasonable, and results in a reduction in depreciation expense of $1.114 million and a reduction to the Company's proposed revenue requirement of $1.152 million.

199. A 60-year estimated life span for the Welsh Unit 2 plant is reasonable (2040 retirement date), and results in a reduction to depreciation expense of $1.042 million and a reduction in revenue requirement of $1.079 million.

Transmission Plant

200. The life parameter of 50 S0 for Federal Regulatory Energy Commission (FERC) Account 355–Poles and Fixtures is reasonable.

201. The net salvage rate of negative 13% for FERC Account 353–Station Equipment is reasonable.

202. The net salvage rate of negative 67% for FERC Account 355–Poles and Fixtures is reasonable.

203. The net salvage rate of negative 40% for FERC Account 356–Overhead Conductor is reasonable.

Distribution Plant

204. SWEPCO agreed with CARD's recommended life parameter of 54 L0 for FERC Account 364–Distribution Poles. This life parameter is reasonable and its adoption reduces SWEPCO's initially requested depreciation expense by $716,339 on a total Company basis and $254,802 on a Texas jurisdictional basis.

205. The net salvage rate of negative 16% for FERC Account 362–Substation Equipment is reasonable.

206. A life parameter of 50 R1.5 for FERC Account 367–Underground Conductor is reasonable. This life parameter results in a $493,969 decrease in annual depreciation expense on a total Company basis for plant as of December 31, 2011, and a corresponding reduction of $175,705 on a Texas retail jurisdictional basis.

General Plant

207. Asbestos removal in 1996 and the sale of an office building in 2004 should be removed from the removal cost and salvage data for FERC Account 390–General Plant for 1984-2011 upon which the net salvage rate for the account should be based. The net salvage rate of negative 3% resulting from this modification is reasonable and reduces SWEPCO's initially requested depreciation expense by $97,594 on a total Company basis and $32,938 on a Texas jurisdictional basis.

Depreciation Reserve

208. The use of the remaining life depreciation method to recover differences between theoretical and actual depreciation reserves is the most appropriate method.

209. It is reasonable for SWEPCO to calculate depreciation reserve allocations on a straight-line basis over the remaining, expected useful life of the item or facility.

Payroll

210. SWEPCO made two adjustments to its test-year payroll. The Company updated payroll costs by annualizing the base payroll to the salary rates in effect at the end of the test year and by recognizing the effect of the merit and general increases that were awarded in 2012.

108. The larger boiler is used and useful, but the prudently incurred cost of the boiler itself is limited to the amount spent to procure the smaller boiler—$3.289 million. Had SWEPCO properly managed its plant construction activities, the smaller boiler would have been installed and the costs of procuring the larger boiler would have been avoided.

109. The smaller auxiliary boiler is not used and useful.

110. DELETED.

111. DELETED.

111A. The amount of $4.268 million was reasonably incurred to erect the larger auxiliary boiler.

112. DELETED.

113. DELETED.

114. A reasonable utility manager would have ensured that the appropriate and cost-effective design solution was the design for which necessary permits were received for the Turk plant.

<u>Turk CCN Costs Cap</u>

115. In Docket No. 33891, the Commission set the Turk plant cost cap at $1.522 billion.

116. SWEPCO's 73.3% share of the $1.522 billion cap is $1.116 billion. Texas's jurisdictional allocation for production plant is 32.7% of SWEPCO's 73.3%.

116A. SWEPCO's share of total construction costs of the Turk plant is $1.106 billion, less the relatively small reductions identified in this order on rehearing. This amount does not exceed SWEPCO's share of the cost cap ($1.116 billion) and should be included in rate base. Texas's jurisdictional share should be recovered from Texas rate payers.

116B. Allowance for funds used during construction (AFUDC) is generally treated as a capital cost in accounting for production plant investment.

116C. The final order in Docket No. 33891 was ambiguous and was not conclusive regarding whether the Commission at that time intended to include AFUDC in the $1.522 billion cap on capital costs.

116D. The cap established in Docket No. 33891 was based on estimates of construction costs excluding AFUDC as testified to by parties to that docket.

116E. AFUDC was a separately calculated component of capital costs that was not intended to be included in the cap.

116F. SWEPCO's share of the roughly $250 million in AFUDC should be included in rate base because the AFUDC was not intended to be included in the cost cap. Texas's jurisdictional share should be recovered from Texas rate payers.

117. DELETED.

118. DELETED.

Welsh Unit 2

119. SWEPCO did not justify with thorough analysis its decision to retire Welsh Unit 2 more than 20 years prior to the end of its useful life.

120. DELETED.

121. DELETED.

122. DELETED.

123. DELETED.

124. The retirement of Welsh Unit 2 has not yet occurred. Consequently, it is inappropriate to consider the unit's retirement costs before it actually happens.

125. It is reasonable for SWEPCO to institute a new proceeding so that the Commission may evaluate the benefits and burdens of retiring Welsh Unit 2.

125A. The determination of whether SWEPCO's decision to reduce production and ultimately retire Welsh Unit 2 was prudent is deferred to a future proceeding that addresses the actual retirement of the plant when it occurs.

Turk Plant – Other Issues

126. SWEPCO recorded $1,372,891,214 as CWIP for direct Turk plant costs at test-year end.

127. The Turk plant went into commercial operation on December 20, 2012.

128. The rate year for SWEPCO's proposed rate increase began on January 29, 2013.

129. On January 29, 2013, SWEPCO's then-existing rates were deemed to be temporary rates for service on or after that date and subject to reconciliation back to January 29, 2013 with a refund or surcharge to the extent that the rates ultimately established by the Commission differ from the temporary rates.

Prepaid Pension Asset and ADFIT Impacts

130. The prepaid pension asset arises under generally accepted accounting principles (GAAP) in accordance with Statement of Financial Accounting Standards No. 87 (FAS 87). The prepaid pension asset represents the amount by which the accumulated contributions to the pension fund exceed the accumulated FAS 87 pension cost.

131. Accounting in accordance with GAAP requires that both the balance sheet and income statement effects be taken into account. GAAP in accordance with FAS 87 requires the amount by which the cash contributions made to the pension fund exceed the accumulated pension cost to be recorded on the balance sheet as a prepaid asset.

132. Investment income on the prepaid pension asset reduces pension cost calculated under FAS 87.

133. As of December 31, 2011, SWEPCO had a prepaid pension asset on its books of $113.2 million calculated in accordance with GAAP. The prepaid pension asset consisted of two amounts for ratemaking purposes:

(a) $80.7 million which is associated with pension cost charged to operation and maintenance (O&M) expense; and

(b) $32.5 million associated with pension cost charged to CWIP.

134. The $80.7 million portion of SWEPCO's prepaid pension asset associated with pension cost charged to O&M expense is appropriately included in rate base.

135. SWEPCO properly included $28.2 million in accumulated deferred federal income tax (ADFIT) as an offset to rate base; this amount is 35% of the $80.7 million prepaid pension asset amount included in rate base.

DOCKET NO. 52487

APPLICATION OF ENTERGY TEXAS, INC. TO AMEND ITS CERTIFICATE OF CONVENIENCE AND NECESSITY TO CONSTRUCT ORANGE COUNTY ADVANCED POWER STATION	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

ABIGAIL B. WEAVER

ON BEHALF OF

ENTERGY TEXAS, INC.

PUBLIC REDACTED

FILED UNDER SEAL

SEPTEMBER 2021

to be necessary if the unit is deactivated. EPG will, as necessary, use the information provided by PowerGen and Transmission Planning to conduct a cost/benefit analysis of keeping the unit operational compared to deactivation and reliance on alternative resources. This cost/benefit analysis includes, but is not limited to, those items described above, along with the impact to other forecasted fixed and variable supply costs, and risks to reliability and economics. When the analysis suggests that the resource no longer meets planning objectives and is in favor of deactivation, the cost/benefit analysis will be presented for a formal decision whether to deactivate. The ETI OC will review the analysis prepared by EPG and make a recommendation to the ETI President and CEO, who will make the ultimate decision whether to deactivate a unit.

If the decision is made to deactivate a unit, the next step in the process is the submission of an Attachment Y Notice to MISO. MISO will then perform a transmission reliability analysis to determine if any near-term violations of applicable transmission planning criteria are caused by the unit deactivation. MISO will approve the Attachment Y Notice if there are no near-term violations of applicable transmission planning criteria or if any identified issues can be resolved by a planned transmission upgrade or other alternative solution prior to the unit deactivation.

Q21. HAS ETI RECENTLY MADE A DEACTIVATION DECISION FOR THE SABINE UNITS?

A. Yes. As part of the economic analysis that identified a 2x1 CCCT as the preferred supply addition to meet long-term needs starting in 2026 (discussed later in my testimony), it was determined that it would be uneconomic to keep Sabine Unit 4 in service instead of constructing OCAPS. Additionally, ETI has studied extending the life of Sabine Units 1 and 3 for a shorter period of time beyond their current deactivation date assumptions of 2023 and 2026, respectively. This analysis evaluated the economics of two scenarios: 1) extend the operation of Unit 1 to 2026, and 2) extend the operation of Units 1 and 3 to five years beyond their current deactivation date assumptions. Both scenarios took into consideration the projected costs to achieve unit availability consistent with recent experience at the respective unit as well as incremental environmental compliance and transmission costs that would be required to operate OCAPS plus both of the Sabine units beyond 2026. In both scenarios, the projected cost to sustain and operate these short-term resources exceeds the value of an equivalent amount of capacity credits obtained from the annual MISO capacity auction based on current projections of auction clearing prices. When comparing the projected cost to an equivalent amount of capacity credits priced at MISO CONE as a sensitivity case, the second scenario remains more costly and the first is only marginally cost effective, but not to a sufficient degree considering other risks of operating Sabine Unit 1 beyond 2023.

Given these evaluations and the commitment needed for the OCAPS Generator Interconnection Agreement, in the August 18, 2021, ETI OC meeting, EPG and PowerGen recommended deactivation of Sabine 1 in 2023, Sabine 3 in 2026, and Sabine 4 in 2026 contingent on OCAPS receiving all necessary approvals and achieving commercial operations. After asking questions of the team, I, along with the other members of the ETI OC, made a recommendation to Ms. Rainer to approve the deactivation of these three units.[7]

ETI along with EPG and PowerGen will continue to monitor these resources, conditions in the market, and reliability of the region, and will return to the ETI OC if there are any material changes that would warrant operating the units beyond these deactivation dates.

Q22. RECOGNIZING THAT THE SABINE UNITS ARE NEARING THE END OF THEIR USEFUL LIVES, IS ONE OPTION TO OPERATE THEM TO FAILURE BEFORE MAKING A FINANCIAL COMMITMENT TO REPLACEMENT CAPACITY?

A. No. ETI must plan for a safe and orderly transition from its reliance on legacy steam generation to the use of modern, efficient technologies. The installation of new resources requires lead time to complete construction and achieve commercial operation. If existing resources were no longer available during that lead time, ETI's customers would be exposed to volatility of market prices for both capacity and energy during that lead time, as well as lose the regional reliability and operational flexibility benefits provided today by the Sabine units. A run to fail strategy is simply too risky from a reliability standpoint, given the transmission-constrained nature of ETI's service territory. Mr. Kline addresses further the transmission-related benefits of ensuring

---

[7] See Exhibit ABW-5.

DOCKET NO. 53719

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

STUART BARRETT

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

Q56. IN ADDITION TO THESE CONTROLS AND PROCESSES, WHAT OTHER MECHANISMS HAS ETI IMPLEMENTED TO ENSURE THAT THE COSTS OF THE CUSTOMER SERVICE ORGANIZATION ARE REASONABLE?

A. Employee cost is one category that can be controlled by any business. Currently, the filling of any vacancy must be justified by a description of need and expected benefit, and must be approved by supervisory leadership. In addition, any new position or changes in positions or organizational structure must be approved by senior management. This “zero-based” hiring process helps to ensure that only critical vacancies are filled and that the addition of personnel involves multiple levels of management oversight.

Q57. WHAT OBJECTIVE EVIDENCE DEMONSTRATES THE CUSTOMER SERVICE ORGANIZATION COSTS ARE REASONABLE?

A. Benchmarking data demonstrates that ETI’s Customer Service organization O&M costs are reasonable. The benchmarking data presented by Ms. Waters for the Retail Operations affiliate class includes both affiliate and non-affiliate customer service O&M costs. As explained by Ms. Waters, the benchmarking analysis shows that ETI is in the 2nd Quartile in cost per customer for these types of customer service expenses.

VII. CAPITAL ADDITIONS

Q58. PLEASE DESCRIBE THE CAPITAL ADDITIONS YOU SPONSOR FOR INCLUSION IN RATE BASE.

A. I sponsor the costs of two of the Power Generation capital additions that are included in Company witness Beverley Gale's Exhibit BG-4. Those projects are separate HEB Grocery Company backup generation experimental projects that I discuss below. Those investments total $2,504,023.

Q59. PLEASE DESCRIBE THE INVESTMENTS THAT YOU SPONSOR FROM MS. GALE'S EXHIBIT BG-4.

A. I support project C6PPTX0004 and project C6PPWS1337 included in Ms. Gale's Exhibit BG-4. Project C6PPTX0004 is a backup generator located at an HEB store in Beaumont, Texas, and Project C6PPWS1337 is a backup generator located at an HEB store in The Woodlands, Texas. The installation configuration for each project includes three 400 kW natural gas generators, totaling 1.2 MW.

In these experimental programs, the backup generators supply power to HEB during an outage while at other times the backup generators are available to supply power to the grid to mitigate energy prices during favorable market conditions. Under both projects, HEB is billed for the backup service through the Company's Additional Facilities Charge Rider – Schedule AFC. Through these experimental programs, ETI is gaining experience to potentially broaden the scope and availability of backup service to a broader customer base.

Q60. ARE THE HEB PROJECTS USED AND USEFUL IN PROVIDING SERVICE?

A. Yes. The backup generator in Beaumont was commissioned in 2021 and is currently providing service to ETI's customers and the host load customer. The backup generator in The Woodlands began operations in 2019 and is currently providing service to ETI's customers. Both units have been called many times to operate and provide power to the electric grid during favorable market conditions. In addition, the backup generator in The Woodlands was activated and supplied power to the HEB store during Hurricane Laura and Winter Storm Uri, allowing the grocery store to remain open and serve local residents during those emergency situations.

Q61. THE HEB PROJECT COSTS INCLUDES AFFILIATE COSTS. ARE THOSE AFFILIATE COSTS NECESSARY TO IMPLEMENT THE PROJECTS?

A. Yes. As explained by Ms. Gale, ETI's capital projects generally include a high percentage of affiliate costs because the nature of the projects. Entergy uses its centralized services company (ESL) to implement customer service programs that benefit all of the EOCs to leverage economies of scale. This approach generally allows the costs attributable to ETI for these types of programs to be less costly than what they would be if ETI created and implemented the programs on its own. The same budgeting and cost control measures discussed by Ms. Gale apply equally to the affiliate charges that were capitalized, as does the discussion regarding the use of a single billing method per project.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.
to the First Set of Data Requests
of Requesting Party: Texas Industrial Energy Consumers

Prepared By: Josh Paternostro
Sponsoring Witness: Allison P. Lofton
Beginning Sequence No. LR843
Ending Sequence No. LR843

Question No.: TIEC 1-24 Part No.: Addendum:

The following discovery requests pertain to the Direct Testimony of Allison P. Lofton.

Question:

Referring to page 43:

a. Does ETI own the two HEB Backup Generators? If so, explain whether the costs of these generators are being allocated and recovered in the base revenues ETI has proposed in this case.

b. State the authority for including the HEB Backup Generators in ETI's cost of service.

Response:

a. Yes, Entergy Texas, Inc. ("ETI") owns the two HEB backup generators. The generators are used and useful in providing service to the public. During normal grid conditions, ETI controls the two generators to provide capacity, energy, and ancillary services to the electrical grid or to otherwise help manage demand. During an outage, the generator provides backup electric service directly to the HEB facilities until service is restored. Because all ETI's customers benefit from the deployment of these generators, ETI has included the costs associated with the backup generators in its requested rate base as plant in service, and in requested base rate revenues. In addition, a portion of the costs for the backup generators are recovered through the Company's Additional Facilities Charge ("AFC") rider, which is used to charge HEB for the backup generators. The AFC revenues for the Test Year are included in the cost of service as "Other Operating Revenues," and offset the amount of the costs included in the proposed base rate revenues for the backup generators.

b. The HEB backup generators are plant in service that is used and useful in providing service to the public and are included in ETI's cost of service pursuant to 16 TAC § 25.231(c)(2)(A).

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Second Set of Data Requests	Prepared By: Kaitlyn Roberts Sponsoring Witnesses: Allison P. Lofton, Richard E. Lain
of Requesting Party: Texas Industrial Energy Consumers	Beginning Sequence No. EV2055 Ending Sequence No. EV2055

Question No.: TIEC 2-10 Part No.: Addendum:

Question:

Please provide a schedule showing how any costs associated with supporting the generation identified in TIEC 2-24 were allocated to Texas retail customers along with workpapers in "live" EXCEL format.

Response:

The costs associated with supporting the generation identified in TIEC 1-24 are included in the Company's requested rate base as Plant in Service. As reflected in Schedule P, page 6, row 98 (Subtotal PLP344: 344 Generators) included in the rate filing package, the costs are allocated to Texas retail customers using the Production Demand allocation factor, PG-DD-TO.

ENTERGY TEXAS, INC.
Electric Service

SCHEDULE UODG

Sheet No.: 160
Effective Date: Proposed
Revision No.: 0
Supersedes: New Schedule
Schedule Consists of: Two Sheets

UTILITY-OWNED DISTRIBUTED GENERATION RIDER

I. AVAILABILITY

N

This Utility-Owned Distributed Generation Rider ("UODG Rider") is available to customers served at Primary or Secondary voltage under rate schedules GS, GS-TOD, LGS, LGS-TOD, LIPS, and LIPS-TOD who enter into a contract with the Company for backup electric service from utility-owned, commercial scale, customer-sited, natural gas-fired distributed generators ("Host Customer(s)"). Such distributed generation will be installed in front of the Host Customer's electric meter.

Unless otherwise expressly provided in a rate schedule, the UODG Rider is not available to customers who are served under the Standby and Maintenance Service Rider (SMS), Rate for Purchases from Qualifying Facilities Less Than or Equal to 100 kW (SQF), Nonfirm Energy Purchased from Large Qualifying Facilities (LQF), Competitive Generation Service (CGS), Economic As-Available Power Service (EAPS), and Rider to Schedule LIPS for Interruptible Service (IS).

II. APPLICATION AND CONDITIONS

Host Customers taking service under this UODG Rider will enter into an Agreement for Backup Electric Service from Customer-Hosted Utility-Owned Distributed Generation ("Agreement") and be responsible for paying a monthly fee designed to recover a portion of the cost to acquire, install, maintain, and operate the Facilities specified in Attachment B of the Agreement.

At the execution of such Agreement, the customer will have a one-time election to select the Recovery Period that will be used to calculate the Host Customer's Monthly Charges applicable over the UODG Agreement Term (defined below). At the Company's sole discretion, the Agreement Term may be modified to a period less than 20 years. The Host Customer's selected Recovery Period must be less than or equal to the UODG Agreement Term.

III. DEFINITIONS

Capacity Value = $77.89/kW-year. For purposes of calculating the Monthly Charges, the Capacity Value will be the value included in the version of this Schedule UODG in effect when the Agreement is executed (such version will be attached for reference as Attachment A to the Agreement).

DG Capacity = the capacity (expressed in kW) of the distributed generator(s) identified as DG Capacity in Exhibit 1 to Attachment B of the Agreement.

(Continued on reverse side)

Energy Value = 32.58% of MISO margins earned by the DG Capacity (*i.e.*, energy or ancillary service-related revenues less costs used to develop generation offers). Margins are subject to subsequent adjustment for MISO resettlements. Such adjustments will be applied to the Energy Value component in the Net Monthly Charge formula. N

Total Installed Cost = the total installed cost of the distributed generator(s) specified in Attachment B of the Agreement.

Host Customer Allocation of Total Installed Cost is the portion of Total Installed Costs that has been allocated to the Host Customer for the costs that are in excess of the Capacity Value, represented by the formula:

> Host Customer Allocation of Total Installed Costs = Total Installed Costs x Host Customer Allocation Percentage

Host Customer Allocation Percentage is determined by calculating the difference between the Levelized Real UODG Value and the Capacity Value. This difference is then compared to the Levelized Real UODG Value and the entire calculation is represented by the formula:

> Host Customer Allocation Percentage = (Levelized Real UODG Value – Capacity Value) / Levelized Real UODG Value

Levelized Real UODG Value is the cost stream that when escalating the first year's cost annually at inflation over the useful life results in the same present value of the lifetime revenue requirement of the UODG asset divided by the DG Capacity, expressed as a $/kW-year amount and identified as Levelized Real UODG Value in Exhibit 1 to Attachment B of the Agreement**.**

IV. MONTHLY CHARGES

The UODG Rider monthly charge during the Recovery Period will be equal to:

> Monthly % During Recovery Period x Host Customer Allocation of Total Installed Costs

The UODG Rider monthly charge to recover O&M expense after the Recovery Period will be equal to:

> Monthly % Post-Recovery Period x Host Customer Allocation of Total Installed Cost

V. UODG RIDER ENERGY VALUE CREDIT

The Monthly Charges defined in Section IV will be reduced by the Energy Value produced by the Host Customer's distributed generator(s), if any.

 (Continued on next page)

UTILITY-OWNED DISTRIBUTED GENERATION RIDER

VI. RECOVERY PERIOD

N

Host Customers define in the Agreement the number of years (the “Recovery Period”) that will define the appropriate monthly rates to be applied to the Host Customer Allocation of Total Installed Cost. The Recovery Period cannot be longer than 20 years. The following table specifies the monthly percentages for application during the selected Recovery Period and any years following the Recovery Period (Post-Recovery Period).

Selected Recovery Period (Years)	Monthly % During Recovery Period	Monthly % Post-Recovery Period
1	9.257%	0.197%
2	4.915%	0.197%
3	3.470%	0.197%
4	2.750%	0.197%
5	2.320%	0.197%
6	2.034%	0.197%
7	1.832%	0.197%
8	1.681%	0.197%
9	1.564%	0.197%
10	1.472%	0.197%
11	1.397%	0.197%
12	1.335%	0.197%
13	1.283%	0.197%
14	1.240%	0.197%
15	1.202%	0.197%
16	1.170%	0.197%
17	1.142%	0.197%
18	1.118%	0.197%
19	1.096%	0.197%
20	1.077%	0.197%

The Recovery Period selected in the Agreement cannot be changed, and Monthly Charges applicable during the Recovery Period cannot be accelerated or prepaid in order to transition to the Post-Recovery Period earlier than scheduled; provided, however, that a Host Customer may make a lump sum payment of any remaining financial obligations associated with the Recovery Period upon Host Customer’s election to terminate the Agreement, as provided below. Under those circumstances (Host Customer termination), Host Customer would no longer receive backup electric service under this Rider UODG and would likewise not be obligated to pay Monthly Charges associated with what would have been any remaining Post-Recovery Period.

(Continued on reverse side)

VII. AGREEMENT TERM

N

The term of the Agreement ("Agreement Term") will be for an initial period of 20 years and automatically will be extended thereafter for successive periods of one (1) year each until terminated by written notice given by one party to the other not more than six (6) months nor less than three (3) months prior to the expiration of the initial Agreement Term or any anniversary thereof.

If the Host Customer ceases to take electric service from the Company or terminates the Agreement during the initial Agreement Term, as discussed above, the Host Customer must still pay the applicable Monthly Charges (either monthly or in a single payment equivalent to the sum of the Monthly Charges) for what would otherwise be due during the remaining Recovery Period, provided that the remainder of the Recovery Period is four years or less. In the event that the remaining Recovery Period is longer than four years, Host Customer must make a single payment equivalent to the sum of the Monthly Charges that would otherwise be due during the remaining Recovery Period. A single payment would be due no later than 30 days after the date of receipt of an invoice from the Company.

VIII. PAYMENT

The past due amount for service furnished for which payment is not made within sixteen (16) days of the billing date will be the monthly bill, including all adjustments under the rate schedule and applicable riders, plus 5%. The 5% penalty on delinquent bills will not be applied to any balance to which the penalty has already been applied. If the amount due when rendered is paid prior to such date, the monthly bill will apply. If providing service to the State of Texas or to municipalities or other political subdivisions of this state, Company will not assess a fee, penalty, interest, or other charge to these entities for delinquent payment of a bill.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the First Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Kelvin Winslow Sponsoring Witness: Melanie Taylor Beginning Sequence No. WG75 Ending Sequence No. WG75

Question No.: TIEC 1-39 Part No.: Addendum:

Question:

Define the specific period that Winter Storm Uri impacted ETI's service area.

Response:

The question does not specify what "impacted" means. However, Entergy Texas, Inc.'s ("ETI") service area first experienced freezing rain that moved into portions of Southeast Texas on the afternoon of February 14, 2021 increasing in coverage and intensity overnight into February 15, 2021. The freeze warnings for the area continued through 9:00 a.m. February 20, 2022.

Thereafter, ETI continued to address impacts of Winter Storm Uri through March 1, 2021.